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Evaluating how Demand Side Resources Affect the Environmental and Economic Performance of Energy Systems

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Abstract

The recent history of energy systems is succinctly summarized as building enough energy extraction, conversion, and delivery infrastructure to meet growing energy demand. Among the benefits of this energy systems framework, we observe that access to modern energy services helps to improve peoples' standards of living and energy consumption has been positively correlated with gross domestic product. Among the draw backs of focusing solely on the supply side of energy extraction, conversion, delivery, and consumption are concerns regarding inefficient energy consumption (i.e. over-consumption of energy) and the growing evidence of large energy-related human, environmental, and climate impacts.

As governments begin to recognize the economic and environmental costs of additional supply side infrastructure, governments, academic institutions, and advocacy groups highlight the "low hanging" nature of demand side interventions. On the surface, demand side interventions offer a win-win situation: use technology or data to identify energy consuming processes that can be optimized (i.e. reduced) or incur very large energy system costs. The energy system becomes more "cost effective" when incentives or regulations can decrease the energy consumption of those processes at a lower cost than actually meeting the baseline energy demand of those processes.

This Dissertation goes further and evaluates how these energy saving policies, incentives, and regulations interact with our existing energy systems in ways that are not immediately apparent. In the second chapter, I assess how mandatory commercial building energy codes can reduce air pollutant emissions and provide social benefits. The U.S. government currently does not use estimates of the benefits of codes to determine the appropriate level of policy stringency

or set adoption incentives and thus systematic estimates of social benefits are necessary. Quantitative estimates of code benefits at the state level that can inform the size and allocation of these incentives are not available. We estimate the state-level climate, environmental, and health benefits (i.e., social benefits) and reductions in energy bills (private benefits) of a more stringent code (ASHRAE 90.1-2010) relative to a baseline code (ASHRAE 90.1-2007). We find that reductions in site energy use intensity range from 93 MJ/m^2 of new construction per year (California) to 270 MJ/m^2 of new construction per year (North Dakota). Total annual benefits from more stringent codes total $506 million for all states, where $372 is from reductions in energy bills, and $134 is from social benefits. These total benefits ranges from $0.6 million in Wyoming to $49 million in Texas. Private benefits range from $0.38 per square meter in Washington State to $1.06 per square meter in New Hampshire. Social benefits range from $0.04 per square meter annually in California to $0.50 per meter foot in Ohio. Reductions in human/environmental damages and future climate damages account for nearly equal shares of social benefits.

In the third chapter, I explore how improvements in building natural gas energy efficiency can help natural gas utilities avoid capital intensive natural gas system infrastructure investments. Recent periods of pipeline congestion, high natural gas and electricity prices, and controversial infrastructure proposals have increased the public and policymaker scrutiny of the existing natural gas system infrastructure and investment process. In order to help inform the debate of New England's energy system options, we estimate the benefits of natural gas end-use efficiency programs for utilities in New England. In particular, we model how efficiency programs affect utility firm pipeline capacity purchases and the excess capacity that utilities resell in the short-term capacity markets (i.e. the "capacity value" of the efficiency program). We find that when the utility currently owns sufficient pipeline capacity to meet demand projections, the capacity value of natural gas energy efficiency measures is high because implementing an efficiency program allows the utility to resell additional excess capacity in the high-value, short-term resale market: $4 to $5 per thousand cubic feet (MCF) of natural gas savings over the life of the space heating efficiency program and $3 per MCF for water heating efficiency programs. When the utility needs to purchase additional firm pipeline capacity to meet projected demand growth, the efficiency program may avoid part of the planned purchase but also resells less excess capacity. For this scenario, the capacity value of space heating efficiency programs is approximately -$2 to -$3 per MCF of natural gas savings, and $1 per MCF for water heating efficiency programs. Given the current capacity situation of utilities across New England, our findings suggest that some existing natural gas efficiency programs in southern New England (CT, MA, RI) may not be cost effective while a greater number of natural gas efficiency programs in northern New England (ME, NH) may be cost effective. The capacity value of natural gas efficiency programs, and thus the cost effectiveness of these programs, is sensitive to the revenue that utilities receive when they sell excess capacity in the short-term market. We recommend that public utility commissions consider including the revenue that utilities receive from reselling excess capacity in the cost effectiveness testing framework for efficiency programs. PUCs could accomplish this by valuing excess pipeline capacity at the basis differential between New England and production areas or by working with utilities and other stakeholders to identify a mutually agreeable value.

In the fourth chapter, I quantify how allowing residential consumer to self-provide electric energy using distributed solar photovoltaic (PV) arrays will change overall electricity system costs in Portugal. Further, I quantify the distribution of the benefits of solar PV among solar panel owning and non-solar panel owning ratepayers.

In 2008, the European Parliament adopted the European Commission's (EC) "20-20-20" goals in order to address global climate change concerns and to tap the potential economic and energy security benefits of energy systems based on renewable energy resources. Under the 20-20-20 package, Portugal needs to produce 60% of total electricity using renewable energy sources (or RES) by 2020. However, the total cost of subsidy policies that lead this transition now account for approximately 33% of residential consumers electricity bills. In light of both the 20-20-20 climate goals and the increasing need to achieve these goals in a cost effective manner, we quantifying the benefits and costs of distributed solar PV in Portugal for panel owners, ratepayers as a whole, and the specific group of ratepayers that does not own solar panels. We measure the benefits and costs of distributed solar PV from these perspectives by computing and comparing the present value of the cost of a distributed solar PV array, the present value of grid electricity purchases that solar panel owners avoid, and the present value of grid generation and delivery costs that the grid avoids when panel owners consume less electricity. We find that solar PV is net present value positive for the average Portuguese electricity ratepayer that owns a solar array. The most attractive option for an average consumer is a 500W array, with a net present value of 700-800€ relative to a present cost of about 1500€. On the other hand, distributed solar PV generation has a higher cost than using the grid to produce and deliver a marginal unit of electricity during periods that solar PV arrays generate electricity. Ratepayers as a whole pay 900-2600€ more in total costs for each kilowatt of distributed solar PV capacity that panel owners install; the 500 W solar array increases total system costs by 1600€. Further, panel owners also avoid paying sunk grid costs, such as revenue guarantees to other renewable generators and the costs of grid infrastructure. In order to recover these sunk costs from ratepayers, retail prices will increase for all consumers. As a result, non-panel owners will pay an additional 1600€ in bills (total across all non-panel owners) for each 500W array that panel owners install. This is equivalent to a 140€/MWh subsidy to panel owners, which is larger than the subsidy that many other Portuguese generators receive but smaller than the subsidy for existing solar PV arrays. Portuguese policy-makers could reduce this subsidy by instituting some type of solar PV fee (more straightforward) or changing the rate structure such that retail prices more closely reflect underlying costs (more complex). Alternatively, Portuguese policy makers could maintain the existing policy. The subsidy per unit of installed solar PV will not change; however, the large number of consumers that live in multi-family housing (and may not be able to install solar PV) suggests that the total value of the subsidy from panel owners to non-panel owners will remain limited.

Table of Contents

Table of Figures

Table of Tables

1 Introduction

The recent history of energy systems is succinctly summarized as building enough energy extraction, conversion, and delivery infrastructure to meet growing energy demand. Among the benefits of this energy systems framework, we observe that access to modern energy services helps to improve peoples' standards of living and energy consumption has been positively correlated with gross domestic product. The "revealed preference" for increasing energy consumption, regardless of the internal and external costs of the required energy extraction, conversion, and delivery infrastructure was a 20th century hallmark in the United States and western Europe. Governments either sponsored, or actually executed, the damming of major rivers, exploitation of vast fossil reserves, construction of power plants without pollution controls, and generally encouraged the growth of energy supplies and demand. While energy demand growth has slowed down recently, the United States and Western Europe continue to consume vast quantities of energy.

Recently, however, citizens in the United State and Europe, among a small set of other nations, began to place a higher value on the costs of energy consumption, including social costs such as the human and environmental damages caused by energy-related pollution. Research is helping to identify and bring to the public eye the drawbacks of focusing solely on the supply side of energy extraction, conversion, delivery, and consumption equation.

In this Dissertation, I assist citizens and policymakers to identify the benefits and costs of interventions that reduce or displace consumer energy demand. I focus specifically on demand side interventions because of the strong citizen and policymaker demand for energy solutions that result in low to no pollution and social costs. Demand-side interventions, such as reducing energy demand through energy efficiency measures or decreasing net energy demand by installing distributed renewable energy resources, are an area of citizen and policymaker interest because such demand side solutions can offer many of the same cost and quality characteristics of supply side interventions but do not increase pollutant emissions. This Dissertation uses benefit-cost analysis of demand-side interventions from a variety perspectives in order to quantify the effects of integrating these demand-side interventions into our existing energy systems.

In Chapter 2, I assess how mandatory commercial building energy codes can reduce air pollutant emissions and provide social benefits. The U.S. government currently does not use estimates of the benefits of codes to determine the appropriate level of policy stringency or set adoption incentives and thus systematic estimates of social benefits are necessary. Quantitative estimates of code benefits at the state level that can inform the size and allocation of these incentives are not available. In Chapter 3, I explore how improvements in building natural gas energy efficiency can help natural gas utilities avoid capital intensive natural gas system infrastructure investments. Recent periods of pipeline congestion, high natural gas and electricity prices, and controversial infrastructure proposals have increased the public and policymaker scrutiny of the existing natural gas system infrastructure and investment process. In order to help inform the debate of New England's energy system options, we estimate the benefits of natural gas end-use efficiency programs for utilities in New England. In particular, we model how efficiency programs affect utility firm pipeline capacity purchases and the excess capacity that utilities resell in the short-term capacity markets (i.e. the "capacity value" of the efficiency program). In Chapter 4, I quantify how allowing residential consumer to self-provide electric energy using distributed solar photovoltaic (PV) arrays will change overall electricity system costs in Portugal. Further, I quantify the distribution of the benefits of solar PV among solar panel owning and non-solar panel owning ratepayers. In 2008, the European Parliament adopted the European Commission's (EC) "20-20-20" goals in order to address global climate change concerns and to tap the potential economic and energy security benefits of energy systems based on renewable energy resources. Under the 20-20-20 package, Portugal needs to produce 60% of total electricity using renewable energy sources (or RES) by 2020. However, the total cost of subsidy policies that lead this transition now account for approximately 33% of residential consumers electricity bills. In light of both the 20-20-20 climate goals and the increasing need to achieve these goals in a cost effective manner, we quantifying the benefits and costs of distributed solar PV in Portugal for panel owners, ratepayers as a whole, and the specific group of ratepayers that does not own solar panels.

2 Evaluating the benefits of commercial building energy codes and improving federal incentives for code adoption

This chapter is based on research that appears in the journal Environmental Science and Technology, as:

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2.1 Abstract

The federal government has the goal of decreasing commercial building energy consumption and pollutant emissions by incentivizing the adoption of commercial building energy codes. Quantitative estimates of code benefits at the state level that can inform the size and allocation of these incentives are not available. We estimate the state-level climate, environmental, and health benefits (i.e., social benefits) and reductions in energy bills (private benefits) of a more stringent code (ASHRAE 90.1-2010) relative to a baseline code (ASHRAE 90.1-2007). We find that reductions in site energy use intensity range from 93 MJ/m^2 of new construction per year (California) to 270 MJ/m^2 of new construction per year (North Dakota). Total annual benefits from more stringent codes total \$506 million for all states, where \$372 is from reductions in energy bills, and \$134 is from social benefits. These total benefits ranges from \$0.6 million in Wyoming to \$49 million in Texas. Private benefits range from \$0.38 per square meter in Washington State to \$1.06 per square meter in New Hampshire. Social benefits range from \$0.04 per square meter annually in California to \$0.50 per meter foot in Ohio.

Reductions in human/environmental damages and future climate damages account for nearly equal shares of social benefits.

2.2 Introduction

Commercial buildings account for approximately 19% of total U.S. energy consumption and are consistently shown to hold technically and economically feasible efficiency options.[1–4] The federal government has set aggressive goals for capturing this potential.[5,6] For example, the goal of the Building Energy Codes Program (BECP) within the U.S. Department of Energy is to reduce annual energy consumption by 1.5 EJ (1 exajoule = 10^{18} joules) by 2030 through the use energy codes.[5] One such code is the *Energy Standard for Buildings Except Low Rise Residential Buildings* (hereinafter ASHRAE 90.1-2010), which was developed in collaboration with the American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE). Like its predecessors ASHRAE 90.1-2007 and 90.1-2004, ASHRAE 90.1-2010 is a commercial building energy code that localities and states can easily adopt and integrate into existing building codes. This code "packages" many of the diverse energy efficiency options available in the commercial building sector into a single policy.[7] All new commercial buildings in locations where the code is adopted must then meet these standards. Existing buildings do not need to be brought up to code if the state adopts a more stringent energy code after a building exists.

ASHRAE 90.1-2010 is expected to reduce the annual energy consumption of an average new commercial building by 19% relative to ASHRAE 90.1-2007.[7] ASHRAE and the Pacific Northwest National Laboratory (PNNL) estimated these savings using the building energy simulation model EnergyPlus and commercial building prototypes designed to minimally comply with the 90.1-2007 and 90.1-2010 code levels.[8] Forty-one individual code amendments are responsible for these predicted savings. These amendments update code requirements for HVAC

(17 amendments), lighting (14 amendments), building envelope (6 amendments), and other components/systems (4 amendments).[7] Table 2.1in the Appendix, Section 7.1, shows the key differences between the code 2007 and 2010 code levels.

The federal government acts to increase the implementation of building energy efficiency options by providing technical and monetary assistance as code adoption incentives for states. Each year, the Department of Energy allocates $26 million in monetary incentives to states according to a formula where one third of this funding is distributed evenly across states, and two thirds are distributed proportionately based on state energy consumption and state population.[9] States qualify for this funding when they meet certain criteria, including the adoption of the most recent commercial building energy code. The revenue available to states through this program is relatively small and so it is unclear how many states adopt codes as a result of the incentives. However, the widespread adoption of ASHRAE 90.1-2007 following a one-time incentive budget increase, from $26 million to $3 billion through the American Reinvestment and Recovery Act, indicates that states are aware of the program. Figure 7.2in the Appendix, Section 7.2, shows the current code level of each U.S. state.

Previous research suggests that building energy consumption, and the effect of commercial building energy codes on energy consumption, vary greatly across building types and climate zones.[7,10–13] Further, states are diverse in their climates, types of buildings constructed, and total amount of commercial floor space constructed.[14] This heterogeneity suggests that the benefits of energy codes could vary significantly between states. However, quantitative estimates of code benefits at the state-level, which could help policymakers set total incentives appropriately and understand how incentive funding compares with potential benefits, are not available. The guidance provided by existing studies is constrained by those studies' limited study scope that focuses on an individual or small number of states and/or their focus on a small subset of commercial building types and climate zones.[15,16] Other available studies do not consider differences between states in the types of buildings constructed and magnitude of total commercial construction.[13,17] Finally, the benefits of energy codes, beyond energy and carbon dioxide emissions savings, are an emerging issue of interest.[18] This paper aims to fill these knowledge gaps by developing and applying a method to estimate state-level social benefits of energy codes for commercial buildings. We focus our discussion on social benefits (i.e., reductions in external costs, such as health and environmental effects, and damages associated with climate change) because the federal government can reasonably spend social resources to capture social benefits.

In this work, we estimate the benefits of a more stringent commercial building energy code (90.1-2010) for new commercial buildings constructed in each individual state in the continental United States. To use a consistent baseline code, we select to use the 90.1-2007 code level for all states (despite the fact that a few states have already adopted more stringent building codes). Our objectives are to assess how the potential energy, climate, environmental, and human health benefits of ASHRAE 90.1-2010 are distributed across states and to compare how well potential benefits align with the magnitude and allocation of the federal incentives designed to capture those benefits. For those states that have already adopted the 90.1-2010 code, our estimates correspond to the benefits that are currently being captured.

2.3 Material and Methods

We estimate state-level energy consumption and emissions for new commercial buildings when new commercial buildings meet both the ASHRAE 90.1-2007 and the 90.1-2010 code. We estimate the monetary value of the benefits of states switching to the more stringent (2010) code level. Our model relies on the key assumptions that new commercial building energy consumption can be modeled using building energy simulation and that monetary estimates of the marginal damages of pollutant emissions reflect the social cost of pollution.

Methods Overview

We estimate state-level energy consumption and emissions for new commercial buildings when new commercial buildings meet both the ASHRAE 90.1-2007 and the 90.1-2010 code. We estimate the monetary value of the benefits of states switching to the more stringent (2010) code level. In Figure 2.1, we show the framework used in this analysis, and here we briefly describe the method used.

We use building prototypes by building type and climate zone that were developed by the Pacific Northwest National Laboratory (PNNL) (see (1) in Figure 2.1). These building prototypes meet either the 2007 or the 2010 code level. We use these building prototypes to estimate energy consumption by fuel and by end use in new commercial buildings. To do so, we use a building energy simulation model -- EnergyPlus (see (2 and 3) in Figure 2.1). We also use historical construction data from the Commercial Building Energy Consumption Survey (CBECS) in order to get total energy consumption by commercial buildings in each state (see (5) in Figure 2.1). The PNNL building types and the building types in CBECS have different building taxonomies. Before getting a total state value, we thus match the PNNL prototype building with the closest CBECS type building (see (4) in Figure 2.1). Through this process, we replicate approximately 80% of the historical energy consumption reported in CBECS using the PNNL building prototypes.

We compute the energy consumption by state for each code level (see (6) in Figure 2.1), and the respective difference in energy consumption between building code levels. We estimate the upstream reductions in emissions of pollutants that affect human health, environmental health (SO_2, NO_x, $PM_{2.5}$), and climate (CO_2) (see 7 and 8 in Figure 2.1). Finally, we convert changes in energy consumption and emissions into monetary values using state specific energy prices as well as location and pollutant specific marginal damage estimates.

We report energy, emissions, and monetary results for a single year (i.e., the first year of a building's life). In addition to single year results, we also report the results for a scenario where more stringent energy codes have an assumed effective lifetime of 10 years and future benefits are discounted at 3% annually. Monetary values from other research are scaled to 2010$ using the Consumer Price Index (CPI). For example, the damages caused by pollution from the AP2 integrated assessment model are scaled from 2000$ to 2010$ using the CPI. In the sections that follow, we provide more details on methods and data.

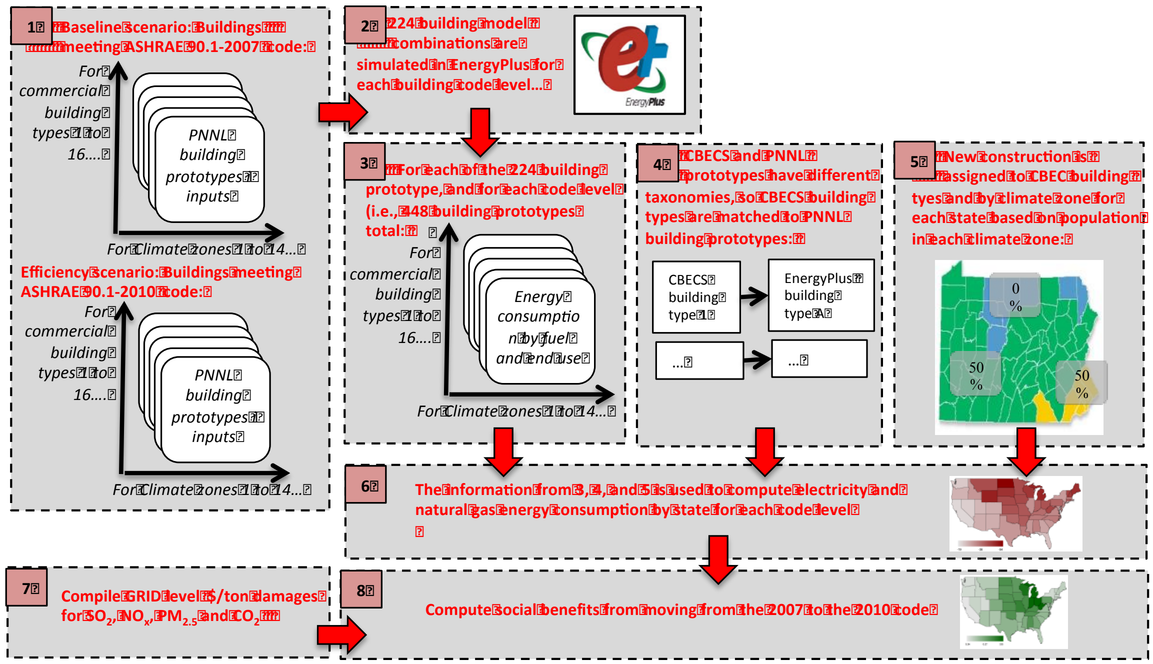

Figure 2.1 Model schematic. Boxes 1, 2, and 3 correspond to the Modeling Commercial Building Energy Use Intensity and Estimating State Level Commercial Building Energy Consumption. Boxes 4 and 5 show how the social benefits of building energy codes are estimated. In box 4, social benefits are attributed to the counties where pollution occurs (i.e., the electricity generators). Note, boxes 4 and 5 illustrate the method of estimating the social benefits of electricity savings, the method for natural gas is slightly different (described below).

Simulating Commercial Building Energy Use Intensity Under Different Code Levels By Building Type and Climate Zone

We use building prototype models from PNNL as inputs to the EnergyPlus software to simulate new commercial building energy consumption for different building types and climate zones.[7] For our baseline, we simulate building energy consumption at the ASHRAE 90.1-2007 code level, the most common energy code level across states in the U.S. We then compare baseline energy consumption with energy consumption at the ASHRAE 90.1-2010 code level. The difference between building models at the 90.1-2007 and 90.1-2010 code levels is the result of the 41 code changes, as described in Appendix Section 7.1. Prototypes exist for 16 building types, including office buildings, retail stores, and schools across 14 U.S. climate and sub-climate zones, resulting in 224 building models for each of the commercial building energy code levels. These prototypes meet the minimum standards of each code level.[7]

EnergyPlus is a freely available building energy simulation model created by the Department of Energy (DoE).[19] EnergyPlus simulates the energy consumption of a building over a chosen time period (e.g. 1 year) using input files that specify building characteristics and weather data (i.e., the building prototypes mentioned above). EnergyPlus performs heat balance calculations at each time step to determine energy losses (e.g. loss through walls, windows, and floors) and gains (e.g. solar insolation through windows, heat gain from lighting/equipment).[20] The characteristics of building systems, such as furnace or air conditioner technology types and efficiencies, determine the amount of electricity or natural gas needed to maintain the desired indoor conditions. Indoor conditions are specified in building operating schedules. Operating schedules also define building characteristics such as thermostat set points, occupancy, equipment operation, and lighting schedules. EnergyPlus also models other (smaller) energy transfers, including heat gain due to lighting and occupancy.[19]

We convert the EnergyPlus simulation results into building energy use intensities (annual energy use per square meter) for delivered electricity and natural gas for all building models. In the Appendix, Section 7.3, we show the baseline energy savings by building type.

A National Research Council report on energy efficiency standards and green building certification suggests that using building simulation models often results in energy consumption estimates that differ substantially from the actual building energy consumption.[21] In order to address this issue, in the Appendix, Section 7.4, we compare the simulated energy consumption of the building prototypes at the 90.1-2004 code level with the actual energy consumption of the

U.S. commercial buildings constructed from 1990 - 2003.[22 23] We use simulated energy consumption at the 90.1-2004 code level for this validation exercise because it most closely matches the CBECS data; CBECS has not published more recent building energy consumption data since 2003. Across all building prototypes, the simulated electricity and natural gas consumption of buildings at the 90.1-2004 code level is similar to the actual electricity and natural gas consumption of equivalent buildings in 2003 (for more details Figure 7.4and Figure 7.5 in Section 7.4). Given the lack of more recent data, we are unable to validate the modeled energy consumption for building prototypes that meet the 90.1-2007 and 90.1-2010 code levels.

Estimating New Commercial Building Constructions by State, Climate zone and Building Type

The goal of this step is to allocate state level estimates of new commercial building construction by climate zone and by EnergyPlus building prototype. A complicating factor is that there are estimates of state-level construction data by CBECS building type, but not by EnergyPlus building prototype.[14] Most CBECS building types aggregate similar building types (for example "offices") whereas EnergyPlus prototypes have a sub-set of categories (i.e., small, medium, and large offices). In the Appendix, Section 7.5, Table 7.2, we show how CBECS building types map to EnergyPlus prototypes. For example, based on PNNL data, CBECS office buildings are divided among small office (38%), medium office (40%), and large office (22%) EnergyPlus prototypes; we assume this ratio is constant across states.[14] With this method, we match approximately 80% of commercial building floor space constructed from 2003 through 2007 (the date range of the PNNL construction dataset) to EnergyPlus prototypes.

We then further allocate state-level construction data for each EnergyPlus prototype across the climate zones within each state. A map of the climate zones of each U.S. county as defined by the Department of Energy is shown in the Appendix, Section 7.6.[24] As suggested in Deru (2011), we allocate new construction to each climate zone in proportion to the fraction of state population change within that climate zone.[25] Population changes for each climate zone in a state are calculated using county level population changes between 2000 and 2010 from the U.S. Census.[24,26] The final output is a dataset for each state that specifies new commercial building floor space by EnergyPlus prototype and climate zone. Population change is well correlated with commercial building construction, as we show in the Appendix, Section 7.7.

Estimating State Level Commercial Building Energy Consumption

Finally, we calculate the total energy consumption of newly constructed commercial buildings in each state by multiplying building and climate specific energy use intensities by building and climate specific estimates of commercial building construction and summing across all states. The result is site electricity and natural gas savings, for a single year, due to increasing the stringency of the building energy code.

Estimating Private and Social Benefits of Building Energy Codes

In order to evaluate the effects of adopting the more stringent code level, we estimate both the private benefits and social benefits that occur due to reductions in energy consumption. For this analysis, we define private benefits as the monetary value of energy bills savings to consumers and calculate private benefits by multiplying changes in energy consumption by state-specific average commercial electricity and natural gas prices from the Energy Information Administration.[27,28]

In order to quantify social benefits of energy savings we follow the method used by the National Research Council (NRC).[29] The NRC calculates the total social cost of pollutant emissions as the product of multiplying county specific pollutant emissions by the county and pollutant specific damages caused by those emissions.

County Specific Social Cost of Pollutant Emissions

The Air Pollution Emission Experiments and Policy analysis (APEEP) integrated assessment model forms the basis of the social cost per unit of pollution for both NRC (2010) and our research.[30] The AP2 integrated assessment model (the most recent version of the APEEP model) quantifies the damages related to human morbidity and mortality, changes in agriculture and time yields, reductions in visibility, damage to human structures, and lost recreational opportunities.[31] In practice, however, human mortality and morbidity account for the vast majority of the dollar value of reducing pollutant emissions.[30] While there are several integrated assessment models that could be used to derive our assumptions for the damages associated with electricity and natural gas (e.g., [32]), we rely on the AP2 integrated assessment model given that it has been extensively used in the literature.[29,33–35] Further, while we note that there is a large uncertainty associated with any exercise that monetizes health and environmental effect associated with air pollution, the output damages from the AP2 integrated assessment model broadly replicate the larger integrated assessment literature. For example per kilogram of pollution $PM_{2.5}$ emissions are the most harmful, followed by SO_2, and NO_x and geography plays an important role in determining the damages caused by pollution.[36] In this paper we use the AP2 integrated assessment model damage values for SO_2, NO_x, and $PM_{2.5}$ for each U.S. County for 2008; these are the most recent damages values that are publicly available.[33,34] Finally, since the AP2 model does not include CO_2, we use a social cost of carbon emissions of \$33 per metric ton of CO_2 in our baseline scenario.[37]

Social Benefit of Electricity Savings

We value changes in emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) that result from decreases in consumption of electricity as a result of the adoption of energy building codes. The social benefit of the more stringent code ($) equals the electricity saved in the state (e.g. MWh), scaled by a transmission loss factor, and multiplied by the reduction in external damages for each unit of source electricity savings (e.g. $/MWh).

To estimate the state average reduction in external damages for each megawatt hour of electricity savings, we first calculate reductions in external damages per megawatt hour for each eGRID sub-region. The electricity grid is highly interconnected and contains generators in discreet locations. Therefore we cannot assume that reducing electricity consumption by one megawatt hour in a given county will correspond to one less megawatt hour of electricity production in that county. Instead, we estimate how a change in consumption affects production, emissions, and social costs for eGRID sub-regions, as described in the next paragraph. We break the U.S. electricity grid into eGRID sub-regions because they "uniformly attribute electric generation in a specific region of the country".[38] A map of the eGRID sub-regions used is shown in the Appendix, Section 7.8. Equation 2.1 shows how we calculate the average social benefit for each eGRID sub-region:

$$\Delta S = \sum_{cty=1}^{CTY} \Delta D_{cty} * ef_{cty} * gen.fraction_{cty} \tag{2.1}$$

Were ΔS is the social benefit per MWh ($/MWh) between using each of the code levels, ΔD is the avoided damage from reducing pollutants in each county ($/ton), *ef* is the emission factor of electricity generators in each county (tons/MWh) and *gen.fraction* is fraction of total sub-region generation that occurs in each county (unitless).

We use generation and emissions data from 2011, the latest year with generation and emissions data for all pollutants. Generation data is from EIA-923 form. Emissions data is from the EPA Clean Air Markets Program (CO_2, SO_2, and NO_x emissions data) and the 2011 National Emissions Inventory (NEI; $PM_{2.5}$ emissions data).[39–41] We then value pollutant emissions using the AP2 integrated assessment model values and the social cost of carbon previously described. Finally, we estimate state averaged social benefits based on the source of electricity generation in the state (i.e., eGRID sub-region). For example, the electricity generation from power plants that are located in Pennsylvania and that belong to the Reliability First Council East (RFCE) account for 70% of total generation in Pennsylvania, so we assume that 70% of damages from RFCE, and 30% of the damages are at the levels from Reliability First Council West sub-region (RFCW). Finally, the state average social benefit rate is multiplied by a regional estimate of average line losses from eGRID to convert from social benefits due to source energy savings to social benefits due to site energy savings.[42]

Social Benefit of Natural Gas Savings

The social benefit of reducing natural gas consumption in buildings ($) is estimated by the site natural gas savings (e.g. GJ) multiplied by social benefit per unit of site natural gas avoided (e.g. $/GJ). Given that reductions in site natural gas will reduce emissions at the building site, we estimate the state average social benefit rate by weighting the avoided external damages in each county by the fraction of construction that occurs in each county. As described above, new construction is each county is based on population change in each county.

We calculate the social benefit rate for CO_2 and NO_x and estimate that other pollutant emissions will be negligible.[43,44] Emissions factors are from the AP-42 emissions factors database: 50.6 $kg_{CO2}/GJ_{natural\ gas}$ and 0.042 $kg_{NOx}/GJ_{natrual\ gas}$.[44] A more recent analysis of natural gas combustion in residential furnaces confirms that AP-42 emission factors reasonably approximate actual NO_x emissions.[43] We value CO_2 emissions using the same social cost of carbon as for electricity, $33 per metric ton, and NO_x emissions using the AP2 integrated assessment model NO_x valuation for ground level emissions. [33,34,37]

2.4 Results

For all results in this section, we denote "social savings" as the reductions in health, environmental and climate change related damages, and "private savings" for the reductions in electricity and natural gas energy bills.

State-Level Effects of ASHRAE 90.1-2010.

Figure 2.2a shows the potential reductions in site energy use intensity for states in the continental U.S., which range from 93 MJ/m^2 of new construction per year (California) to 270 MJ/m^2 of new construction per year (North Dakota). States have different changes in building energy use intensity due to differences in climate, variations in building energy savings across climate zones, and also differences in the mix of buildings constructed in each state. However, total potential energy savings Figure 2.2b) correlate strongly with total area of new commercial construction and are highest in states with the largest amounts of new construction.

Figure 2.2c and 2.2d show the changes in SO_2 emissions. We highlight SO_2 because it accounts for 78% of total human and environmental damages and 38% of total social benefits when including the climate benefits of avoided CO_2 emissions. This finding is in agreement with existing integrated assessment literature: SO_2 pollution causes the greatest human and environmental damages (accounts for the greatest share of benefits) despite the fact that SO_2 causes less damage per ton than $PM_{2.5}$ because of the large number of tons emitted (saved).[34,45 46] Potential savings of other pollutant emissions are shown in the Appendix, Section 7.9. Potential emissions savings depend on both state level building construction rates and the emissions intensity of electricity production in individual states. States with large amounts of construction only have large emission reductions (relative to other states) if the grid emission rate is non-negligible; states with small amounts of construction do not have large emission reductions.

Figure 2.2e and 2.2f show the annual social (i.e., health, environmental and climate change) benefits of adopting the 90.1-2010 building energy code. Annual social benefits range from \$0.04 per square meter in California to \$0.50 per square meter in Ohio. As with changes in emissions, we find a strong correlation between social benefits and the amount of new commercial construction but only when social benefits per unit of energy savings are non-negligible. Figure 2 also highlights that federal policy makers should differentiate between states with high energy, emissions, and social benefits intensity and states with large total energy, emissions, and social benefits. Incentivizing states based on the intensity of benefits will not necessarily incentivize the states with the largest total benefits.

To date, 13 states (California, Delaware, the District of Columbia, Illinois, Iowa, Massachusetts, Maryland, Mississippi, Oregon, Rhode Island, Utah, Virginia and Washington) have adopted ASHRAE 90.1-2010. According to our model these states account for 18% of national social benefits, 25% of national private benefits, and 23% of total benefits.[47] Given that these states have adopted ASHRAE 90.1-2010, our results provide a first order estimate of the benefits that these states are already capturing.

Ten other states (Arizona, Colorado, Kansas, Maine, Minnesota, Missouri, Oklahoma, South Dakota, Tennessee, Wyoming) continue to have building codes that are below the 90.1-2007 level. Those 10 states represent 16%, 13% and 14% of our computed nationwide social benefits, private benefits, and total benefits. When we re-run our analysis assuming that these 10 states have adopted the ASHRAE 90.1-2004 as a baseline code level, we estimate the benefits of adopting the 90.1-2010 code, in these states, is approximately 38% larger that when the 90.1-2007 code is used as the baseline (Appendix Section 7.10).

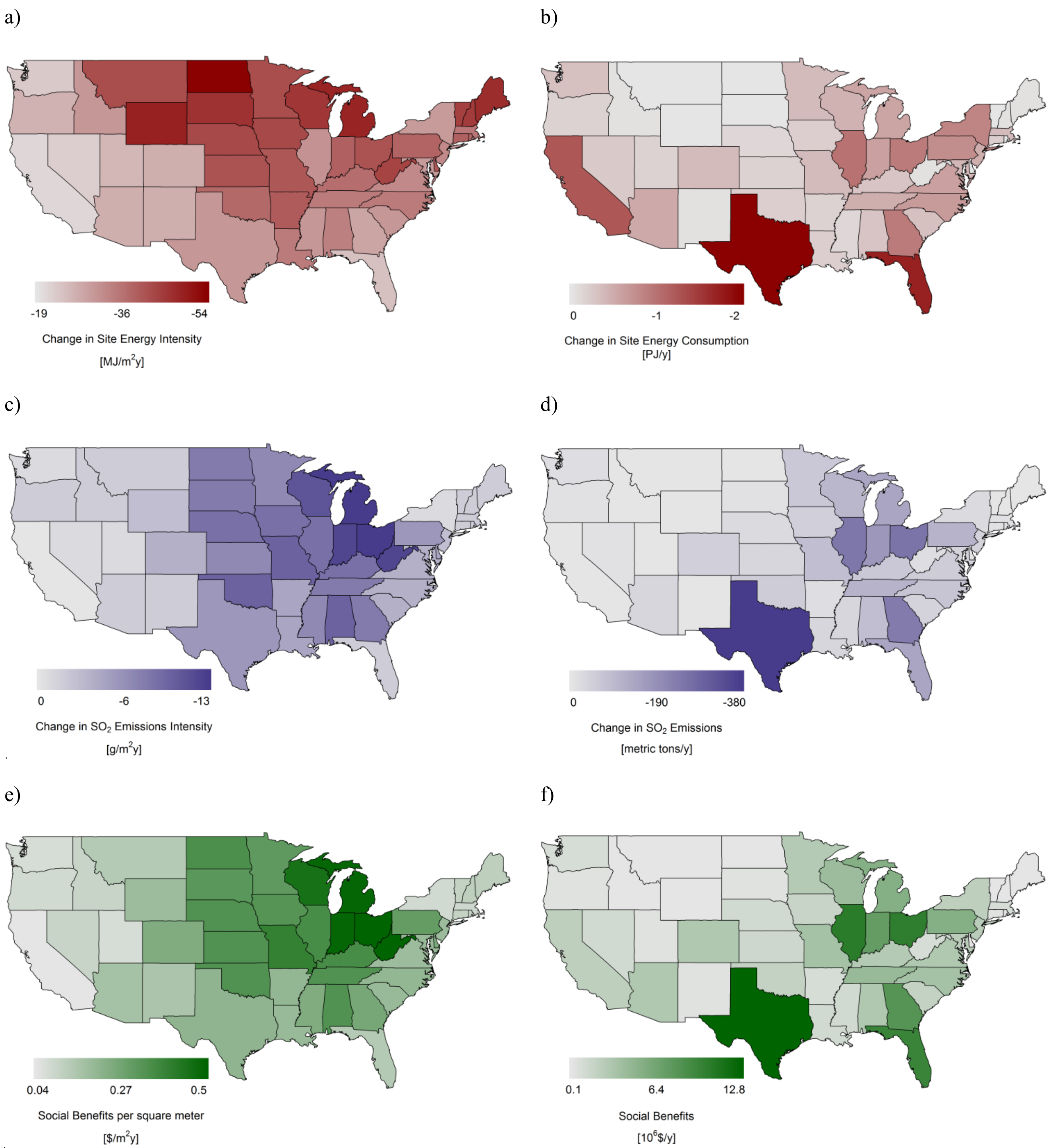

Figure 2.2 The effect of each state switching from ASHRAE 90.1-2007 to 90.1-2010 in terms of intensity and total savings. Figures show a) site energy use intensity and b) state annual site energy consumption c) new building SO_2 emissions intensity d) state annual SO_2 emissions e) building code annual social benefits per unit of floor space constructed, and f) annual social benefits from adopting the more stringent code.

State-level effects vary across states by orders of magnitude between the states with the highest and lowest potential benefits. Additionally, the potential benefits of commercial building energy codes are relatively concentrated, with about 20% of states holding about 50% of benefits across most of the metrics evaluated. The same group of states consistently provides large fractions of potential benefits.

Figure 2.3 shows state-level private and social benefits associated with the reductions in energy consumption for one year of operating all new commercial building at the 90.1-2010 code level instead of the 2007 level. Of the $506 million first-year benefits estimated by our model, private benefits account for 74% ($372 million) of total benefits and social benefits account for the remaining 26% ($134 million). Reductions in electricity expenditures account for the majority of private benefits. For the social benefits, reductions in human/environmental damages and future climate damages account for nearly equal shares of social benefits. The fraction of total benefits that accrue privately versus socially varies substantially across states. In all states, the reductions in energy bills are larger than the reductions in environmental, health, and climate change damages. For example, private benefits account for half of total potential benefits in Ohio; while private benefits account for the majority of total potential benefits in California. Social benefits will scale linearly with the value of human and environmental impacts. For example, if the social cost of carbon is assumed to be $65 per ton of CO_2 instead of $33, then social benefits increase to 35% of total benefits from 26% of total benefits.[46]

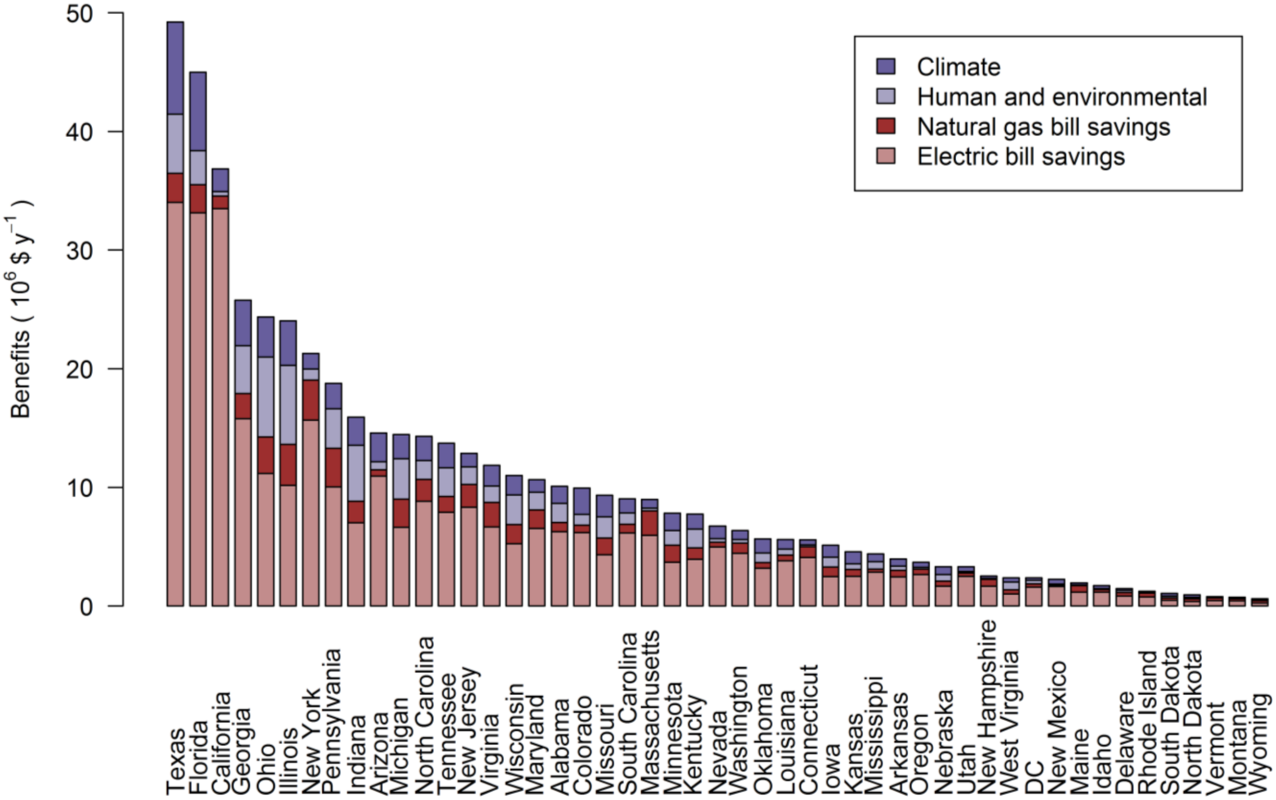

Figure 2.3 Total annual potential benefits of commercial building energy codes by state for one year worth of new building construction. Private benefits correspond to reductions in electricity and natural gas expenditures. Social benefits correspond to the reductions in human and environmental damages and avoided climate damages.

Figure 2.3 shows the *annual* private and social benefits of adopting the more stringent energy code. Lifetime benefits will be much larger. To account for this, we review electric and natural gas utility energy efficiency program documentation and find that most efficiency measures are expected to last at least ten years.[48,49] Using ten years as a first order estimate of the effective lifetime of building codes, we estimate the present value social benefits for the amount of new floor space constructed in a year. For example assuming the new floor space was constructed in 2011 (and using emissions factor projections from 2011 to 2021), the present value benefits over a 10-year period would be \$990 million. If instead we perform the same calculation but exclude the 13 states that have already adopted the 90.1-2010 code, this value amounts to \$800 million in present social benefits nationwide.

Comparing Social Benefits and Current Federal Incentive Adoption Incentives

When states adopt building energy codes, society has the potential to realize social benefits from reductions in fossil energy consumption and emissions of air pollutants. Policies to improve building codes and incentivize the adoption of building codes are an important mechanism for capturing these potential benefits.

We evaluate the effectiveness of the current incentive policies by asking whether the magnitude of building code benefits are similar to the incentive funding provided to capture those benefits. Nationally, for the 38 states that have not adopted the 90.1-2010 code, approximately $800 million dollars (present value) in social benefits are foregone the first year codes are delayed. If code adoption is delayed five years then cumulative foregone social benefits reach $3.5 billion. These benefits are substantially larger than the $26 million in annual incentive funding provided to states. The large magnitude of the social benefits suggests that federal policy makers should re-evaluate the resources being allocated to building code related efforts. Policymakers should consider increasing the incentives dedicated to increasing code adoption if two conditions are met. First, policymaker should believe that increasing incentives will increase code adoption; this hypothesis is supported by the broad adoption of more stringent codes after the American Recovery and Reinvestment Act funds temporarily increased incentives substantially.[47,50] Second, the total federal and state resources being devoted to codes (including current incentives, administrative costs, technical assistance, and implementation and enforcement costs) should not exceed the social benefits of the codes or increasing funding will not increase net social benefits. If these conditions are met, we recommend that federal policymakers consider increasing the resources devoted to the adoption of more stringent building energy codes.

Next, we compare the percentage of social benefits provided by each state with the percentage of total incentive funding provided to each state, i.e., the equitability of the allocation mechanism used by the federal government (Figure 2.4), under the assumption that the goal is to reduce health, environmental and climate change related damages. If the goal of the incentive funding formula is to allocate incentive dollars at an equal rate per unit of benefits across states, then the points in Figure 2.4 should lie along a 1:1 line. We find that the current funding scheme misallocates approximately 25% of annual incentive funds, or $6.4 million annually. The current allocation formula would more equitably distribute incentives based on potential social benefits if Florida, Georgia, Illinois, Indiana, Ohio, and Texas received larger incentives and California and New York received smaller incentives. The underlying cause for this funding misallocation is that the incentive allocation formula does not take into account average grid emissions rates; funds are allocated based on population and energy consumption only. Our results indicate that energy and population are an important start to equitably allocating incentives, but an improved model would consider state average grid emission rates as well. To be clear, according to our analysis, all states seem to be underfunded, but some are relatively more underfunded than others. We do highlight the caveat that we haven't considered the costs for program implementation.

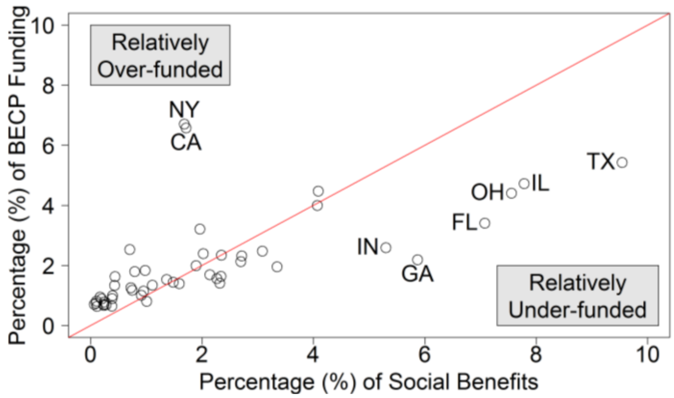

Figure 2.4 Percentage of annual Building Energy Codes Program (BECP) funding each state receives (y-axis) versus the percentage of social potential benefits, excluding private benefits (x-axis). The solid line indicates a 1:1 ratio between percentage of national benefits and percentage of national incentive funding. The distance on the y-axis between each point and the solid line shows the discrepancy between potential benefits and actual funding; points above the line show relatively over-funded states and points below the line show relatively under-funded states. The states with the largest discrepancies between funding and potential benefits are labeled.

One important caveat is that more stringent building energy codes must be cost-effective from a private standpoint in order for the federal government to provide incentive funding and technical assistance related to codes. Specifically, increases in building first costs will offset some of the private benefits of building energy codes. Several recent studies estimate the changes in building first costs associated with more stringent building energy codes (Kneifel, 2011; Thornton, 2013). These studies confirm that individual building energy efficiency upgrades, and certain more stringent codes as a whole, have lower capital costs than the present value of the energy savings over the life of the building. On the other hand, these estimates are complex and sensitive to input assumptions regarding, at a minimum, how fast energy costs grow, how "lifetime" of efficiency improvements that the code mandates, and the rate at which the analyst discounts future benefits.

2.5 Sensitivity Analysis

We vary model parameters to assess the sensitivity of model results to data uncertainty. Specifically we vary the allocation of buildings across (1) climate zones, (2) building types, and (3) the energy savings of buildings meeting 90.1-2010 relative to meeting 90.1-2007.

Additionally, we vary (4) the emission rates of pollutants emitted during electricity production. We test the sensitivity of (1) and (2) because population change is an imperfect proxy for construction and because allocating commercial construction data to a set of prototypes involves judgment and is likely to be imperfect.[14] We test (3) building energy simulations have often over-estimated actual energy savings.[21,51] Finally, we test parameter (4) because existing emissions regulations are projected to change grid emission rates substantially in the future.

We perform a Monte Carlo simulation that randomly varies the fraction of building floor space allocated to each climate zone and building type, parameters (1) and (2). We provide additional details on the method and findings of this analysis in the Appendix, Section 7.11. Model results are largely insensitive to changes in the allocation of buildings across climate zones: reallocating “x” percent of buildings to different building types or climate zones results in a less than “x” percent change in results for nearly all simulations. The low sensitivities indicate that uncertainty in the building construction mix and distribution will not change our qualitative conclusions.

To quantify the effect of decreased building energy savings on total potential energy savings, parameter (3), we reduce both the electricity and natural gas energy savings of a single building type by 25% and rerun the model. We repeat the process for all 16 building types. When energy savings is reduced by 25% total energy savings are reduced by up to 5% in in retail buildings, the building type that accounts for the largest shares of total construction. Total state energy savings are reduced by less than 1% for most other building types. Total energy savings are most sensitive to changes in the energy savings of retail stores, secondary schools, hospitals, and large hotels. Above average increases in efficiency for hospitals and large hotels drove the large reductions in total energy savings when building energy savings was reduced. Above average annual construction for retail and secondary schools drove the large reductions in total energy savings when building energy savings was reduced. We provide further discussion on the energy savings of individual building types in the Appendix, Section 7.11. Misestimating the energy savings of more than one building type has an additive effect on our results (e.g. misestimating two building types that each individually reduces state savings by 1% and 2% yield a total reduction in savings of 3%).

Social benefits will also change due to changes in electricity grid emission rates, parameter (4), but future emission rates are uncertain. We use EIA projections of electricity grid emission rates to provide a first order estimate of future code benefits, with the understanding that such projections are inherently uncertain and often very different from actual emissions. EIA provides electricity grid emissions rate projections by eGRID sub-region for CO_2, SO_2, and NO_x.[52] We assume $PM_{2.5}$ emission factors change proportionately the SO_2 emission factor, but that the marginal damage of pollutant emissions remains constant. Then, we rerun the model using emissions projections through 2040 (Appendix, Section 7.11, Figure 7.13). We find that the social benefits of 90.1-2010 are likely to decrease over the next ten years and then to remain near $100 million annually through 2040 (Table 2.1, nominal dollars). We provide additional discussion of the changes in benefits at the state level in the Appendix, Section 7.11.

Table 2.1 Benefits of the 90.1-2010 energy code, relative to the 90.1-2007 building energy code. In all cases, the benefits refer to the amount of floor space constructed in one year. In (a) we show the annual savings, in nominal dollars, for one year worth of construction in 2011, 2020 or 2040. The difference across years is due to different pollution emissions rates for those years, using historical emissions rates in 2011, and projected emission rates from the EIA, for 2020, and 2040.[52] Health and environmental benefits assume that marginal damages of NO_x, SO_2, and $PM_{2.5}$ pollution ($ per ton of pollutant) remain constant over time.[34] We value climate benefits using the EPA social cost of carbon ($33/metric ton of CO_2).[37] In (b) we show the 10-year present value benefits of one year worth of new construction for year 2011. Future benefits are discounted at 3% annually.

Social Benefits (10^6 $/y)	(a) Single year worth of construction benefits (nominal	(b) Ten Year PV; buildings constructed

	dollars)			in:
	2011 (baseline)	2020	2040	2011
Human / Environmental	65	27	28	380
Climate	69	70	68	610
Total	**134**	**97**	**96**	**990**

In general, our findings and conclusions are not sensitive to uncertainties in the distribution of construction across building types and climate zones, the energy savings of an individual building type, and projections of electricity grid emissions rates. If the emissions intensity of the electricity grid decreases as projected, then the potential annual benefits of adopting 90.1-2010 are likely to decrease slightly over the next ten years, but remain substantially larger than the incentive funding provided to states through 2040. Climate benefits will also shift to accounting for two thirds of social benefits, an increase from the one half of social benefits they provide today. De-carbonization of the electricity grid would virtually eliminate the emission benefits of building energy codes. However, there are no signs that such a de-carbonization will take place in the coming decades.

Future Work

We estimate the social health, environmental and climate change benefits, and the savings from reduced energy bills that may occur when states adopt more stringent building energy codes. We find that the benefits vary substantially across states and building types. Given that individual building efficiency programs are also implemented, such as utility energy efficiency programs targeted at individual appliances or building types, it is important to develop estimates of the social benefits provided by individual efficiency measures. Additionally, we use a conservative estimate of effective code lifetime to estimate net cost of deferring code adoption; other researchers have assumed longer building lifetimes when estimating benefits. Further research should be conducted to clarify the effective lifetime of building codes and therefore the benefits that a state forgoes when choosing to not adopt a more stringent code. We anticipate factors such as building renovation rates, the lifetime of efficiency measures, and energy efficiency 'learning curves' should be incorporated into such a decision analysis model.

Finally, we calculate social benefits using annual average emissions factors at the eGRID sub-region level. Recent research has suggested that grid emission rates vary by time of day and season. Future work should quantify the differences in emissions savings estimates between average emission factors and "marginal emissions factors" for common efficiency measures and how these differences may affect decision making.

2.6 Conclusion

Quantitative estimates of the social benefits of more stringent building codes at the state level, which could help set incentives levels and make allocation decisions, have not been available. We assess how the potential energy, climate, environmental, and health benefits of a more stringent code (ASHRAE 90.1-2010) are distributed across states relative to the baseline code (ASHRAE 90.1-2007). We find that total potential energy savings, emissions savings, and monetary benefits correlate strongly with total area of new commercial construction. The amount of floor space constructed each year in the U.S. provides an annual benefit of $134 million which includes human, environmental, and climate benefits. Assuming the code has an effective lifetime of ten years, the present social benefits of one year worth of new construction are $990 million. These benefits are substantially larger than the $26 million in annual federal incentives provided to states to spur code adoption. Further, we find that social benefits will remain substantially larger than the federal incentive funding levels when considering projected reductions in grid electricity emissions intensity. Finally, the current incentive allocation formula does not fund states based on potential social benefits and misallocates 25% of the funds. We recommend that federal policy-makers increase the incentives for adopting more stringent energy codes, if policy-makers 1) believe that larger incentives will increase the adoption of more stringent building energy codes; 2) find that total current spending across federal and state programs directed at building energy codes is smaller than the social benefits reported here and policymakers; and 3) the marginal social benefit of increasing incentives is larger than the marginal social cost of increasing incentives.

3 Quantifying the capacity value of natural gas energy efficiency measures in New England

This chapter is based on research that has been submitted to the journal Energy, as:
Gilbraith, N.; Jaramillo, P Azevedo, L. Quantifying the capacity value of natural gas energy efficiency measures in New England. Energy.2015. (submitted).

3.1 Abstract

Natural gas utilities in New England increasingly act as critical elements of the New England energy system. Natural gas utilities both meet the demand of natural gas consumers and resell excess pipeline capacity to natural gas fueled electricity generators. Recent periods of pipeline congestion, high natural gas and electricity prices, and controversial infrastructure proposals have increased the public and policymaker scrutiny of the status quo. In order to help inform the debate of New England's energy system options, we estimate the benefits of natural gas end-use efficiency programs for utilities in New England. In particular, we model how efficiency programs affect utility firm pipeline capacity purchases and the excess capacity that utilities resell in the short-term capacity markets (i.e. the "capacity value" of the efficiency program). We find that when the utility currently owns sufficient pipeline capacity to meet demand projections, the capacity value of natural gas energy efficiency measures is high because implementing an efficiency program allows the utility to resell additional excess capacity in the high-value, short-term resale market: \$4 to \$5 per thousand cubic feet (MCF) of natural gas savings over the life of the space heating efficiency program and \$3 per MCF for water heating

efficiency programs. When the utility needs to purchase additional firm pipeline capacity to meet projected demand growth, the efficiency program may avoid part of the planned purchase but also resells less excess capacity. For this scenario, the capacity value of space heating efficiency programs is approximately -$2 to -$3 per MCF of natural gas savings, and $1 per MCF for water heating efficiency programs. Given the current capacity situation of utilities across New England, our findings suggest that some existing natural gas efficiency programs in southern New England (CT, MA, RI) may not be cost effective while a greater number of natural gas efficiency programs in northern New England (ME, NH) may be cost effective. The capacity value of natural gas efficiency programs, and thus the cost effectiveness of these programs, is sensitive to the revenue that utilities receive when they sell excess capacity in the short-term market. We recommend that public utility commissions consider including the revenue that utilities receive from reselling excess capacity in the cost effectiveness testing framework for efficiency programs. PUCs could accomplish this by valuing excess pipeline capacity at the basis differential between New England and production areas or by working with utilities and other stakeholders to identify a mutually agreeable value.

3.2 Introduction

Recent natural gas price volatility, natural gas transmission pipeline congestion, increasing electricity prices, and controversial pipeline expansion proposals have brought New England's natural gas infrastructure under increasing scrutiny. For example, New England states continue to pay higher natural gas and electricity prices than neighboring states, despite increasing shale gas production in neighboring regions. In fact, spot natural gas prices in New England have become more volatile over the past several winters and spot prices reached historic highs during the 2013-2014 winter [53]. While increasing the capacity of natural gas transmission pipelines across New England states could alleviate some of these constraints, such expansion projects remain controversial. Critics of expanding natural gas transmission pipelines worry about issues related to ecosystem protection, the potential for inefficient ratepayer financing of infrastructure projects, and potentially enhancing our dependence on fossil-based energy systems. These critics also highlight the existence of potential clean energy substitutes [54]. Recent and substantial amendments to the New England governors' high-profile pipeline expansion proposal – which now backs away from calling for expanding natural gas pipeline capacity for all New England states – highlights the complexity of reducing pipeline congestion and price volatility [55].

The various sources of resistance to expanding pipeline capacity in New England must be carefully considered due to the participatory process that governs the natural gas system in New England. The process of changing an aspect of the natural gas system is a judicial style process that involves opening a "docket" on a particular topic and inviting comments and discussion from parties with a stake in the proceeding. It is very common for natural gas dockets to contain comments from consumer advocates, environmental advocates, state and local governments, the utilities themselves, and a variety of other interests. Public utility commissions are required to accept and consider the information submitted through this process in their choice of paths forward

While residential and commercial consumers are the primary concern of natural gas local distribution utilities (herein after, natural gas utilities), electricity generators and other large natural gas consumers also heavily rely on natural gas utilities to meet their supply needs. As previously mentioned, natural gas utilities own large quantities of both "long-haul" firm pipeline capacity from producing areas to New England, and "short-haul" firm pipeline capacity within

New England [56]. They are thus the primary firm capacity holders in the region. Electricity generators and other large natural gas consumers often rely on firm capacity holders not using all of their firm capacity rights and re-selling this capacity to other consumers [57]. The dependence of electricity generators, in specific, on the excess capacity of natural gas utilities has even started to threaten the reliability of the electricity systems during periods that natural gas utilities consume all or nearly all of their firm pipeline capacity [57]. Thus natural gas utilities, as both owners of firm capacity rights and suppliers of excess capacity to electricity generators, are key stakeholders in the larger New England energy system.

New England natural gas utilities work to provide natural gas service for their firm customers (i.e. most residential and small commercial customers) at just and reasonable rates. To meet this goal, utilities use firm pipeline capacity during the summer to transport natural gas from producing regions into New England storage sites. During the winter, which is the high demand season, utilities rely on both firm pipeline capacity from producing regions and firm pipeline capacity from natural gas storage sites to meet demand. Further, utilities will use off-system peaking resources to meet demand during the highest demand days of the year (approximately 10 days each year [56]). Off-system peaking resources are locally stored fuel supplies that do not require firm pipeline capacity to deliver them to customers, such as liquefied propane gas or liquefied natural gas [56]. Finally, all six states (Connecticut, Maine, Massachusetts, Rhode Island, New Hampshire, and Vermont) also have policies or laws that allow (or require) utilities to capture cost effective energy efficiency in order to avoid natural gas system costs such as natural gas purchases or natural gas infrastructure investments (Appendix, Table 8.1). Such energy efficiency programs can thus act as a substitute for purchasing additional natural gas or pipeline capacity. Public utility commissions and natural gas utilities continuously work together to choose the resource portfolio that leads to a least cost system. Table 3.1 shows that public utility commissions already rely on natural gas efficiency programs to offset billions of cubic feet per year of natural gas demand and spend hundreds of millions of dollars annually to procure these savings.

Table 3.1. Statistics related to natural gas energy efficiency programs in New England. Data are from: [58–66]. Maine did not estimate the cost effectiveness of their natural gas energy efficiency programs due to the small total program budget [67]. Note: the cost per unit of natural gas savings is not the lifetime savings divided by the program budget because such an analysis would consider the consumer's increase in costs (e.g., marginal cost of the efficient equipment). *We report benefit cost ratios for commercial and industrial programs since our research addresses commercial building efficiency programs.

State	2013	2014	2015
	Total natural gas energy efficiency budget (10^6\$)		
CT	43.6	48.5	51.4
MA	168.4	174.6	180.1
ME	-	0.5	0.5
NH	6.3	7.1	6.7
RI	18.3	25.8	24.5
Total	236.6	256.5	263.2
	PUC accepted total lifetime savings estimate (MCF)		
CT	8,550,927	9,411,764	10,399,561
MA	31,277,136	31,277,136	31,277,136
ME	-	53,300	54,000
NH	1,781,409	1,897,430	2,036,173
RI	3,830,689	4,427,735	4,048,728
Total	45,440,161	47,067,364	47,815,598
	*PUC accepted benefit-cost ratio (B/C)**		

CT	0.83	0.87	0.87
MA	2.24	2.28	2.42
ME	n/a	n/a	n/a
NH	2.10	2.14	1.78
RI	2.14	1.87	2.23

Given the increasing congestion of natural gas transmission pipelines in New England, the central role that natural gas pipelines play in New England's electricity and natural gas system, and the role of natural gas efficiency programs as a potential substitute for additional transmission pipeline capacity, it is important to understand the benefits that natural gas efficiency programs provide to natural gas utilities in New England, considering recent changes in pipeline congestion and the potential effects of natural gas utility actions on the overall natural gas system. In order to accurately quantify these benefits, public utilities commissions (PUCs) direct utilities to use standardized cost effectiveness tests to consistently compare the benefits and costs of energy efficiency programs and implement only those programs that are cost effective [58,68–72]. Regulators also specify the appropriate benefits and costs to include in the cost effectiveness test. PUCs in New England generally allow utilities to monetize the energy savings from efficiency programs using values from the Avoided Energy Supply Costs in New England (AESC) report. This AESC report is a collaborative effort by utilities, utility commissions, and consultants to estimate the avoided energy system costs when a utility implements an electricity or natural gas efficiency program; it is updated biannually and was published most recently in 2013 [56]. Finally, the PUCs in New England generally require that utilities estimate the energy savings of an efficiency program using Technical Resource Manuals (TRMs) [49,56,73–76]. TRMs are documents that establish methods to estimate the energy savings of individual efficiency interventions and provide reference energy savings values for a wide variety of common efficiency interventions.

When a utility implements a natural gas efficiency program, the utility avoids the purchase of additional natural gas, potentially avoids the purchase of additional natural gas system infrastructure, avoids pollution compliance costs, and may also accrue other less-tangible benefits [56]. The benefits fall into two categories: benefits that accrue as efficiency avoids variable system costs and benefits that accrue as efficiency avoids fixed system costs. The 2013 AESC report quantifies both the variable and the fixed cost savings of natural gas efficiency programs.[56] The primary variable cost that a utility avoids is the avoided cost of purchasing an additional unit of natural gas. Other, smaller, avoided variable costs include the variable costs associated with using a natural gas pipeline. Fixed costs that a utility avoids can include the costs of firm pipeline capacity to meet demand, the costs of maintaining storage space to recall winter gas reserves, or the costs of maintaining peaking facilities to meet demand above pipeline capacity on the highest demand days [77]. The 2013 AESC report values the fixed costs that an efficiency program avoids by quantifying the amount of firm pipeline capacity avoided by an efficiency programs and using utility data to estimate the price of this capacity [78–80]. The AESC report further recognizes that utilities sign long-term firm capacity contracts that incur monthly fees regardless of whether the utility needs or uses the capacity. Thus, in the short to medium run, efficiency cannot avoid the cost of previously signed contracts for firm natural gas pipeline capacity. However, the current valuation approach does not account for revenues the utilities collect when they resell or release excess firm capacity rights. These revenue streams exist and offset consumer energy costs [56]. The two scenarios below explore how the capacity value of natural gas energy efficiency programs may change when accounting for the fact that utilities resell (or release) excess firm pipeline capacity.

Scenario 1 (No firm capacity shortfall) *Efficiency programs reduce the use of pipeline capacity that the utility already owns*. An efficiency program will decrease demand relative to the 'no efficiency' scenario. However, if the utility does not plan to purchase additional firm pipeline capacity because, for example, load growth projections do not indicate demand will exceed existing capacity, then efficiency will not avoid firm pipeline costs. In this scenario, existing firm pipeline costs do not decrease because the utility must continue to pay the pipeline company for previously purchased firm pipeline capacity, even if it needs less capacity than was initially purchased [80–82]. The 2013 (current) AESC report recognizes that firm capacity contracts are sunk costs and that natural gas efficiency programs cause only small reductions in fixed costs (i.e., firm pipeline capacity costs). However, AESC does not consider that utilities can sell excess capacity and use the revenues to offset customer costs [56,83–87]. The revenue the utility receives from the additional excess capacity sales is a benefit of the efficiency program [88].

Scenario 2: (Firm capacity shortfall) *Efficiency programs reduce the amount of new firm pipeline capacity that the utility needs to purchase*. If current pipeline capacity will not meet projected demand, then an efficiency program could potentially reduce demand by an amount large enough to decrease the quantity of new firm pipeline capacity that the utility needs to purchase. The 2013 AESC report estimates the magnitude and value of such reductions in firm pipeline capacity purchase requirements. However, when a utility purchases less firm pipeline capacity, relative to the 'no efficiency' scenario, the utility will also have less excess firm capacity available for resale. Currently, the AESC does not consider the effect of changes in firm capacity on short-term capacity resale (an opportunity cost). An alternative valuation method is thus to value the avoided firm capacity purchases at the net price of firm capacity. The net price of firm capacity is the marginal price of firm pipeline capacity plus the change in short term capacity resale revenue that is associated with the change in total firm pipeline capacity.

In this paper, we estimate the capacity value of multiple natural gas energy efficiency programs in New England considering both the changes in both firm pipeline capacity purchases and excess capacity resale that result from the changes in demand for natural gas, and discuss the implications of our results on natural gas energy efficiency programs in New England. Table 3.2 summarizes the differences between the energy efficiency valuation models in this paper and the existing AESC avoided costs estimates.

Table 3.2. A breakdown of the potential benefits (or costs) that the current (AESC) method incorporates when estimating the avoided costs of natural gas efficiency programs and the benefits and costs we incorporate in this research.

	Δ in excess capacity resale?	Δ in firm capacity purchases?
2013 AESC Report	No	Yes
Scenario 1 – No Firm Capacity Shortfall	Yes	Yes*
Scenario 2 – Firm Capacity Shortfall	Yes	Yes

*Note: the change in firm capacity purchases is zero for Scenario 1 because utilities cannot avoid the costs of existing firm pipeline capacity contracts.

3.3 Data and Methods

We estimate the capacity value of natural gas energy efficiency programs by incorporating the marginal effect of efficiency on the utility's long-term firm capacity purchases and short-term excess capacity resale. We define a natural gas efficiency program's "capacity value" as the present value of the changes in firm pipeline capacity purchases plus the present value of changes in excess capacity resale. First, we model how each efficiency program changes the natural gas demand of the utility (i.e. total customer demand). To do so, we use the building energy simulation model EnergyPlus to quantify the natural gas consumption of commercial buildings in New England for baseline and higher efficiency. We then convert changes in demand into changes in a utility's firm pipeline requirements and the quantity of excess capacity resale. Finally, we monetize changes in capacity requirements using the marginal price of firm pipeline capacity. We use our framework to estimate the capacity value of five natural gas efficiency programs that New England states commonly offer to commercial buildings.

Estimating natural gas savings from efficiency programs.

We use the building energy simulation model EnergyPlus to calculate the change in statewide natural gas consumption between the 'no efficiency' and efficiency scenarios for existing commercial buildings. Gilbraith *et al*. (2014) and its accompanying Supplemental Information provide a more detailed description of the EnergyPlus model, how it simulates building energy consumption, what considerations and end uses EnergyPlus captures, and how to quantify the building mix within a state [89]. In order to run the Energy Plus model, we rely on commercial building prototypes of common commercial buildings developed by the Pacific Northwest National Laboratory (PNNL). From these general building prototypes, PNNL created a specific version of each building prototype that complies with each combination of three energy code levels and fifteen climate zones [7]. For the 'no efficiency' scenario, we use building prototype models that comply with the 90.1-2004 energy code level and the climate zone of the New England states. We assumed that the 90.1-2004 code is representative of the energy efficiency of the existing commercial building stock. Meteorological data (which are necessary to estimate building energy consumption) are Typical Meteorological Year (TMY3) data for the largest city in each climate zone of each New England state. TMY3 meteorological data are a composite dataset of actual historical meteorological data that both accurately reflect average meteorological conditions and the range of weather present in a given location[90].

In order to model the high-efficiency scenarios, we rely on actual equipment efficiency requirements from utility-sponsored natural gas efficiency programs in New England [91–97]. These requirements specify the minimum efficiency of new equipment that is eligible to participate in the program (Table 3.3). Based on these utility data, we define five high efficiency scenarios: high efficiency furnace retrofit, very high efficiency furnace retrofit, high efficiency boiler retrofit, very high efficiency boiler retrofit (all space heating efficiency programs), and a high efficiency water heater retrofit. We set the equipment efficiency for each building in our model to a value representative of the minimum equipment efficiency that is eligible for the efficiency program (as shown in the last row in Table 3.3) and re-calculate natural gas consumption using EnergyPlus.

Table 3.3. A summary of natural gas energy efficiency rebate programs offered by each state in New England. We show programs for hot water heaters, furnaces, and boilers; some states have additional programs, for example, directed at kitchen equipment. Furnaces and boilers are separated into High Efficiency (HE) and Very High Efficiency (VHE) programs. When a program exists in a state, we show the minimum eligibility requirements in terms of equipment efficiency. Multiple measures of equipment efficiency are used. TE: thermal efficiency. AFUE: annual fuel utilization efficiency. EF: energy factor. The last row of the table shows the efficiency level modeled in the high efficiency scenarios.

	Hot Water Heater		**Boiler**		**Furnace**		
Location	**HE**	**VHE**	**HE**	**VHE**	**HE**	**VHE**	**Ref.**
Southern New England							
Connecticut	Storage: ≥ 0.90 TE; On-demand: ≥ 0.85 EF	-	≥ 0.82 TE / 0.85 AFUE (size dependent)	≥ 0.92 TE / AFUE (size dependent)	≥ 0.90 TE	≥ 0.92 AFUE	92,93
Massachusetts	Storage: ≥ 0.67 EF; On-demand: ≥ .82 EF	Storage: ≥ 0.95 TE; On-demand: ≥ 0.94 EF	≥ 0.90 TE / AFUE (size dependent)	≥ 0.95 AFUE	≥ 0.95 AFUE	≥ 0.97 AFUE	95
Rhode Island	On-demand: ≥ .82 EF	Storage: ≥ 0.95 TE; On-demand: ≥ 0.95 EF	≥ 0.90 TE / AFUE (size dependent)	≥ 0.95 AFUE	≥ 0.95 AFUE	≥ 0.97 AFUE	96
Northern New England							
Maine	-	-	≥ 0.85 TE / AFUE (size dependent)	≥ 0.9 AFUE	-	≥ 0.95 AFUE	91

New Hampshire	Storage: ≥ 0.67 EF; On-demand: ≥ .82 EF	Storage: ≥ 0.95 TE; On-demand: ≥ 0.94 EF	≥ 0.90 TE / AFUE (size dependent)	≥ 0.95 AFUE	≥ 0.95 AFUE	≥ 0.97 AFUE	94
Vermont	Storage: ≥ 0.67 EF; On-demand: ≥ .82 EF	≥ 0.94 TE or ≥ 0.91 EF	≥ 0.87 AFUE	≥ 0.92 AFUE	≥ 0.94 AFUE	-	97
How we model these programs:							
All states	0.95 EF	-	0.87 AFUE	0.95 AFUE	0.95 AFUE	0.97 AFUE	

Daily natural gas savings correspond to the 'no-efficiency' natural gas consumption minus the natural gas consumption in the higher efficiency scenario, measured on the basis of one square foot of building floor space. We estimate statewide daily natural gas savings for an "average" unit of floor space using a weighted average of the daily natural gas savings of all building types. The weight assigned to each building type is the fraction of total commercial building floor space that the building type represented in the Northeast census region in the 2003 CBECS survey [22]. For example, the floor space of office buildings is approximately double that of warehouses. Thus, when we quantify average daily natural gas savings of an efficiency program, we weight the daily natural gas savings per square foot of office buildings twice as heavily as warehouses.

Estimating the volume of firm pipeline capacity the efficiency program avoids.

We convert the natural gas savings of the efficiency program into a change in the firm pipeline capacity requirements of the utility (cubic feet per day of firm capacity rights per thousand cubic feet natural gas savings over the life of the efficiency program). To do this, we first assume that the natural gas savings that result from the efficiency programs are perfectly correlated with natural gas demand. That is, peak day savings for the efficiency program occurs on the peak demand day for the utility, the second highest day of savings corresponds to the second highest demand day, and so forth. This assumption is important because utilities purchase firm pipeline capacity and size peaking facilities based on the demand on peak days. We validate this assumption in the Results section and in Appendix Section 8.4. Finally, we account for the fact that most utilities use locally stored peaking resources to shave demand on the highest demand days and determine firm pipeline capacity requirements accordingly [56]. Therefore, we compute the firm capacity that the efficiency program avoids as the mean daily natural gas savings from the efficiency program over the period of off-system peaking resource use. Based on the AESC report, we assume that all utilities use off-system peaking resources to meet peak demand on the 10 highest demand days of the year in the base case scenario. Equation 3.1 shows how we calculate the firm pipeline capacity that an efficiency program avoids. Appendix Section 8.5 shows the full derivation of Equation 3.1. As we discuss in the Introduction, efficiency programs can only reduce firm pipeline capacity purchases when the utility faces a capacity shortfall.

$$c = if(capacity\ shortfall = T) \left\{ \frac{\sum_{t=1}^{10} s_{t,*}}{10} \right\} else\ \{0\} \tag{3.1}$$

Where 'c' is the firm pipeline capacity savings of the efficiency program (cubic feet per day of pipeline capacity) and 's_t' is the natural gas savings of the efficiency program on day 't' in cubic feet per day, '*' indicates a day the utility uses peaking supplies.

Modeling changes in excess capacity resale due to efficiency programs.

Natural gas efficiency programs could also change the amount and timing of excess capacity that the utility resells. However, both the utility's total firm capacity and demand in each period determine the quantity of excess capacity that the utility can resell. Equation 3.2, which we derive in Appendix Section 8.6, quantifies the annual change in the utility's excess capacity resale considering both variables. In Equation 3.2, 's_t' represents the natural gas savings of the efficiency program (in cubic feet per day) and 'c' represents the firm capacity value of the natural gas efficiency program from Equation 3.1 (in cubic feet per day of pipeline capacity). Equation 3.2 assumes that the utility's excess capacity resale is equal to the difference between the utility's total firm pipeline capacity and natural gas demand in each time period.

$$\Delta resale = \sum_{t=1}^{365} s_t - 365 \times c \tag{3.2}$$

In Scenario 1 (No Firm Capacity Shortfall), since the capacity value of efficiency programs is zero, then each cubic foot of natural gas savings from the efficiency program translates into one additional cubic foot of excess capacity that the utility can resell. In Scenario 2 (Firm Capacity Shortfall), the efficiency program decreases natural gas demand (thus contributing to more excess capacity resale) and decreases total firm pipeline capacity (thus contributing to less excess capacity resale) relative to the 'no efficiency' scenario. The overall effect of the efficiency program on utility excess capacity resale is the net of these two effects.

Valuing Changes in Firm Pipeline Capacity Requirements.

For our base case, we use the price of capacity on the Spectra Algonquin Incremental Expansion project of \$0.43/CF/d (\$1.19/MCF) as the price of pipeline capacity for all of New England [98]. The Spectra AIM project serves as our base case because it is a relatively large pipeline expansion project that is expected to go into service within the next five years [99]. We vary the price of firm pipeline capacity as part of the sensitivity analysis. Utility regulatory filings and pipeline company information suggest that new firm pipeline capacity from the Marcellus Shale region to New England has an annual price of \$0.2 to \$0.8 for each cubic foot per day of capacity ($/CF/d) for utilities in southern New England [56,78,98–101]. We assume utilities in northern New England can purchase firm capacity for the same price (however, we note that we cannot verify this assumption because utilities in northern New England have not made recent commitments to purchase large amounts of firm pipeline capacity [56]). Assuming the utility fully uses the capacity (1 cubic foot per day of capacity can transport 365 cubic feet of natural gas per year), these capacity prices are equivalent to $0.5-$2.2 per thousand cubic feet ($/MCF) of natural gas transported through the pipeline each year.

Monetizing Changes in Excess Capacity Resale:

We convert changes in excess capacity resale to changes in revenue using the market value of short-term pipeline capacity from the Marcellus Shale (Dominion South pricing hub) region to New England (Algonquin Citygates pricing hub). Based on MacAvoy (2007), we assume the value of short-term pipeline capacity is equal to the difference in prices (basis) between Marcellus Shale pricing points and New England (Appendix Section 8.7) [102]. Since gas futures markets only extend five years into the future, we assume that futures prices in year five continue unchanged from year six to year fifteen (the end of the efficiency program). We test the sensitivity of our estimated short term capacity value on the results in the sensitivity analysis.

Table 3.4 shows all key model inputs for the base case, low capacity value, and high capacity value scenarios. We follow the AESC report and assume efficiency programs last for fifteen (15) years [1], [19]–[23]. Additionally, we retain the assumptions in the technical resource manuals (TRMs) for natural gas efficiency programs in New England, which do not account for any degradation of energy savings over time, free-rider, or spill-over effects [19]–[23]. Lastly, we do not evaluate the capacity value of efficiency programs in Vermont because

Vermont is the only New England state that is not directly interconnected with the U.S. natural gas pipeline system

Table 3.4. Model inputs used to estimate the capacity value of natural gas efficiency programs in each region of New England. Southern New England includes Connecticut, Massachusetts, and Rhode Island (CT, MA, RI); Northern New England includes Maine and New Hampshire (ME, NH). The value of capacity resale is not specific because the average value of a unit of capacity resale depends on when natural gas savings occurs due to changes in the value of capacity throughout the year. We report the effective value of capacity resale (average revenue received for each unit of resale) with the results.

Model Variable	**Unit**	**Low**	**Base case**	**High**	**Source**
New Capacity Cost					
Southern New England	($/CF/y)	0.2	0.43	0.66	
Northern New England	($/CF/y)	0.2	0.43	0.66	
Vermont	($/CF/y)	-	-	-	
Needs to Purchase Add'l Capacity?					
Southern New England	(Yes/No)		Yes		
Northern New England	(Yes/No)		No		
Vermont	(Yes/No)	-	-	-	
Capacity Resale Value					
Southern New England	($/MCF)*	0.1, 6.9	0.3, 14	0.4, 21	
Northern New England	($/MCF)*	0.1, 6.9	0.3, 14	0.4, 21	
Vermont	($/MCF)	-	-	-	

Discount Rate				
Southern New England	(%)	1	4	7
Northern New England	(%)	1	4	7
Vermont	(%)	-	-	-
EE Lifetime	(years)		15	
Day where peaking resources are utilized	(days)	0	10	20

*Note: the difference in natural gas prices between the Marcellus Shale and New England (the metric we use to value short term pipeline capacity) varies throughout the year. We provide the lowest and highest price difference, which occur during the summer and winter, respectively.

3.4 Results

Changes in Utility Firm Pipeline Capacity Requirements.

Figure 3.1 plots the relationship between a utility's natural gas demand and the natural gas savings of a furnace and natural gas water heating efficiency program. See Section 8.4 of the Appendix for a description of the utility natural gas demand data. This figure shows that the days with the highest natural gas demand correspond to the days with the highest natural gas savings from both efficiency programs. Thus Figure 3.1 reasonably validates our assumption that peak period natural gas demand and peak period efficiency savings exhibit perfect correlation. Appendix Section 8.8 also validates our estimates of the distribution of natural gas savings from efficiency programs across the year, which is a key determinant of the capacity value of the efficiency program (as discussed further below).

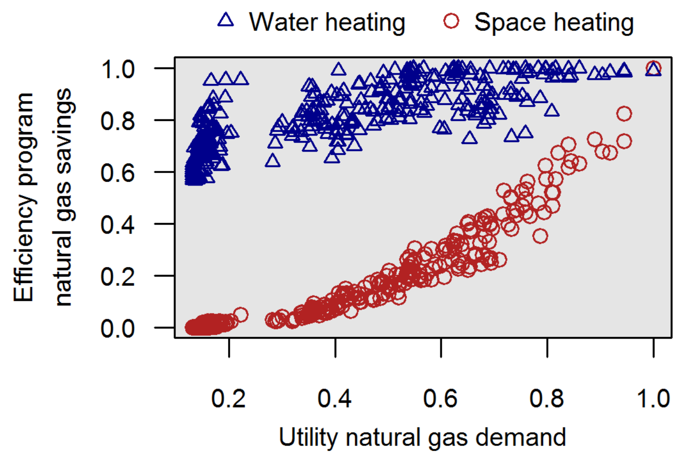

Figure 3.1 Pairs of daily efficiency program natural gas savings (building natural gas savings in Massachusetts, from EnergyPlus building prototypes, weighted by the fraction of existing commercial floor space that each building prototypes represents; y-coordinate) and daily utility natural gas demand (from National Grid in Massachusetts; x-coordinate). We normalize both efficiency program natural gas savings and utility natural gas savings (i.e. maximum value equals one). We observe that daily demand during peak periods corresponds with peak natural gas savings from both efficiency programs. This reasonably validates our assumption that peak utility demand correlates perfectly with peak efficiency program savings.

As previously mentioned, in Scenario 1 (No Firm Capacity Shortfall) the utility does not expect to purchase additional firm pipeline capacity to meet demand, but since utilities must pay for all existing firm capacity contracts, there are no savings from avoiding firm capacity purchases due to natural gas efficiency programs. On the other hand, in Scenario 2 (Firm Capacity Shortfall), the change in firm capacity requirements is the mean daily quantity of natural gas saved over the number of days that the utility uses off-system peaking resources to meet demand. For this scenario, we find that space heating programs avoid larger volumes of capacity requirements than water heating programs, due to the peak-coincident natural gas savings of the space heating programs: space heating programs avoid between 0.7 cubic feet per day (CF/d) and 0.9 CF/d of firm pipeline capacity purchases per MCF of natural gas savings while water heating efficiency programs avoid 0.2 CF/d of firm pipeline capacity per MCF natural gas savings. Based on our base case price of firm pipeline capacity in New England ($0.43/CF/y), we find that the present value of using efficiency to offset new firm pipeline capacity purchases in Scenario 2 is substantial: approximately $1 per MCF of natural gas savings for water heating efficiency programs and $3 to $4 per MCF of natural gas savings for space heating efficiency programs. Table 8.9 in the Appendix provides a detailed breakdown of these results.

Changes in Excess Capacity Resale due to Efficiency

Efficiency programs in Scenario 1 (No Firm Capacity Shortfall) decrease the utilization rate of existing pipeline capacity rights, and therefore increase the utility's excess capacity resale. Since we report all results per MCF of natural gas savings, the increase in excess capacity resale is 1 MCF by definition. The time of year when the changes in resale occur depends on the efficiency program. Space heating programs (i.e., boilers and furnaces) deliver most savings and increase capacity resale during the winter months, while baseload efficiency programs (i.e., hot water heaters) consistently deliver savings and increase capacity resale throughout the year (Figure 3.2a). The monetary value of excess capacity resale in Scenario 1 corresponds to the monthly change in excess capacity resale due to the efficiency program multiplied by the difference in natural gas futures prices between the Marcellus Shale and New England for that month (Figure 3.2b). We find that the value of excess capacity resale is $4 to $5 per MCF of natural gas saved for space heating programs and about $3 per MCF of natural gas saved for water heating programs in Scenario 1.

In Scenario 2 (Firm Capacity Shortfall), efficiency decreases total natural gas demand and also reduces the amount of new firm capacity the utility purchases compared to the 'no efficiency' scenario. The change in short-term capacity resale is the net of these two individual effects. Space heating efficiency programs, which deliver peak-coincident natural gas savings, decrease total short-term capacity resale. That is, the reduction in excess capacity resale because the utility purchases less firm pipeline capacity is greater than the increase in excess capacity resale because utility's natural gas demand decreases. Specifically, for each 1 MCF of natural gas that space heating efficiency programs save, a utility resells between 3 and 4 fewer MCF of excess pipeline capacity. Similarly, water heating efficiency programs, which provide baseload natural gas savings, decrease the amount of excess capacity the utility resells by approximately 0.2 MCF for each 1 MCF of natural gas saved (Figure 3.2c). Efficiency programs that deliver off-peak energy savings would increase short-term capacity resale; however, none of the programs we assess fall into this category. In Scenario 2, there is thus an opportunity cost associated with efficiency programs. We find that space heating efficiency programs reduce excess capacity resale revenue by $5 to $7 per MCF of natural gas saved and water heating programs reduce resale revenue by $0.4 per MCF of natural gas saved. For both space heating and hot water heating efficiency programs, the high natural gas price differential during the winter months drives the change in resale revenue (Figure 3.2d). This is despite the fact that most of the utility's reduction in excess capacity resale occurs during the summer months for space heating efficiency programs.

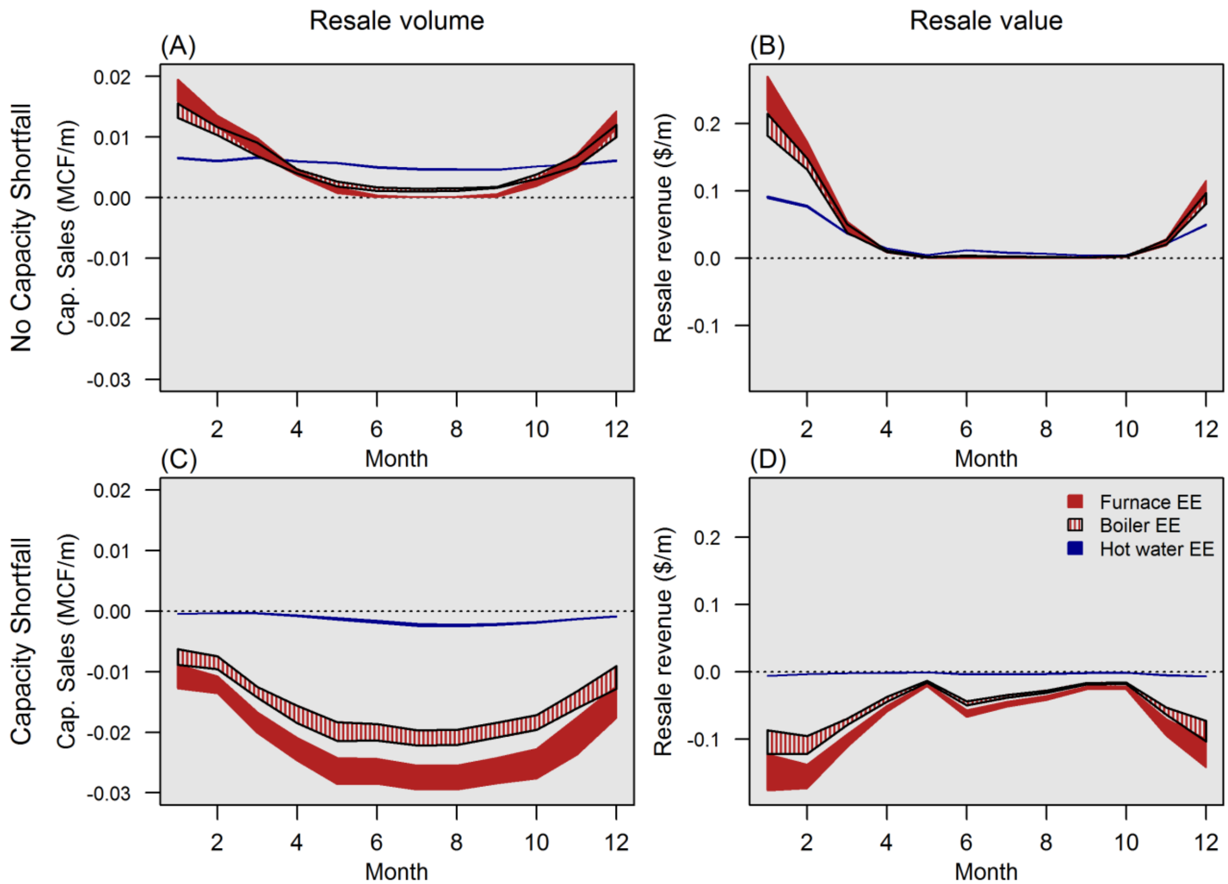

Figure 3.2. Shows the changes in excess capacity resale volume (thousand cubic feet per month, MCF/m; left column) and revenue (dollars per month, $/m; right column) for the different types of natural gas energy efficiency programs. (A) and (B) shows the results for Scenario 1 (No Firm Capacity Shortfall) and (C) and (D) show results for Scenario 2 (Firm Capacity Shortfall). The shaded area for each program type shows the full range (min. to max.) of savings across the seven cities we use to represent the six New England states and the two equipment efficiency levels (High and Very High).

Table 3.5 shows the present value of capacity savings for each MCF of natural gas saved as a result of the efficiency programs. In Scenario 1 (No Firm Capacity Shortfall), the capacity value is large and positive for both space heating and water heating efficiency programs. In Scenario 2 (Firm Capacity Shortfall) the capacity value is negative for space heating efficiency programs and the capacity value is modest and positive for water heating efficiency programs. Space heating programs have a negative capacity value because the large reduction in resale revenue fully offsets the savings from purchasing less firm pipeline capacity.

Table 3.5. Capacity value of difference efficiency programs using base case model inputs. Two scenarios are shown: when the utility projects that load growth will require the purchase of new firm capacity ("Shortfall") and when the utility does not project the need to purchase new firm capacity ("No Shortfall"). PV = present value. Capacity values are simple averages of the capacity value across all states. For example, the value of hot water heating efficiency programs in Scenario 1 is the average value of hot water heating efficiency programs across all states, assuming no states face a capacity shortfall. Alternatively, the value of furnace efficiency programs in Scenario 2 is the average value of furnace efficiency programs across all states, assuming all states face a capacity shortfall.

Scenario	**Type of Program**	**Firm Capacity Savings (CF/d)**	**Change in Capacity Resale Volume (MCF)**	**PV of Firm Capacity Savings**	**PV of Excess Capacity**	**Total Net Present Capacity Value**
Scenario 1 (No Capacity Shortfall)	*Boiler*	0.00	1.00	$0.00	$4.43	$4.43
	Furnace	0.00	1.00	$0.00	$5.07	$5.07
	Hot water heater	0.00	1.00	$0.00	$2.75	$2.75
Scenario 2 (Capacity Shortfall)	*Boiler*	0.70	(2.84)	$3.49	-$5.16	-$1.67
	Furnace	0.90	(3.92)	$4.47	-$7.22	-$2.75
	Hot water heater	0.23	(0.24)	$1.13	-$0.35	$0.78

Table 3.5 also suggests that natural gas energy efficiency programs may not help increase the pipeline capacity that is available for non-firm natural gas customers, such as electricity generators, to purchase from natural gas utilities. This is because our results show that if a utility faces a capacity shortfall, then natural gas energy efficiency programs may actually decrease the amount of excess capacity that the utility resells relative to not implementing an efficiency program. Thus policymakers should not assume that expanding natural gas utility efficiency programs will enable natural gas generators to purchase sufficient natural gas pipeline capacity to ensure a reliable electricity grid.

Table 3.6 shows the capacity value of natural gas efficiency programs for southern and northern New England. Based on our review of utility planning documents, we assume that utilities in southern New England face a firm capacity shortfall while utilities in northern New England do not (Table 8.10 in the Appendix). The large difference in the capacity value of natural gas efficiency programs between the "No firm capacity shortfall" and "Firm capacity shortfall" scenarios highlights the effect of the capacity situation of the utility on the capacity value of natural gas efficiency programs in New England. Thus, we recommend that if PUCs incorporate the resale value of excess capacity in the avoided costs method, then they also consider the capacity situation of utilities. While the capacity value of natural gas efficiency programs varies substantially across regions, these values are relatively constant across states within each region (Table 8.12 in the Appendix).

Table 3.6. Our estimates of the capacity value of natural gas energy efficiency programs, which we group into "Space heating programs" and "Non-space heating programs" for consistency with the AESC report. We assume that the average of furnace and boiler efficiency programs represents the value of "Space heating programs" and water heating programs represent the value of "Non-space heating programs". Regional capacity values are a simple average of the capacity value for each state in the region. Southern New England is Connecticut, Rhode Island, and Massachusetts. Northern New England is composed of New Hampshire and Maine. Capacity values are calculated using the base case input values from Table 3.4 in the Methods.

Region	**Space Heating Programs**	**Non-space heating programs**
	Net present capacity value of each MCF of program savings ($/MCF)	
Southern New England	-$2.4	$0.8
Northern New England	$4.7	$2.7

Next we compare our estimate of the total avoided costs of natural gas efficiency programs the current AESC estimates. To do so, we need to monetize the other (i.e. variable) cost savings of efficiency programs. We add our capacity savings results (i.e. fixed cost savings) to a levelized present price of natural gas over the life of the efficiency program, which we assume is a rough estimate of the variable cost savings of an efficiency program. For consistency with the 2013 AESC report, we assume the levelized present price of natural gas is $5 per MCF over the period from 2013-2028 [56] (see Appendix Section 8.12). While natural gas prices may have changed since 2013, the estimates in this analysis highlight the difference between our method and the AESC method of estimating the benefits of energy efficiency programs. We estimate that total avoided costs, which are the avoided capacity costs plus avoided commodity costs, of space heating efficiency programs in southern New England are $2.2 per MCF of natural gas savings, which is approximately 33% of the $6.6 per MCF of natural gas savings that the 2013 AESC reports [56]. Conversely, we estimate the total avoided costs of space heating efficiency programs in northern New England are $10.6 per MCF of natural gas savings, or 140% of the $7.5 per MCF of natural gas savings the 2013 AESC reports [56] (Figure 3.3).

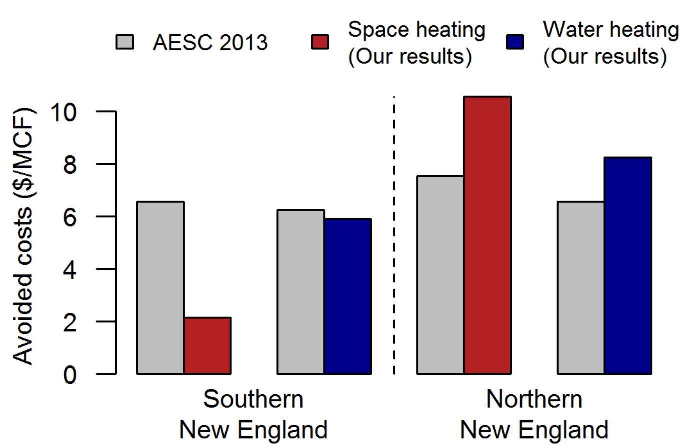

Figure 3.3. A comparison of the natural gas system costs avoided by end-use efficiency measures for the AESC report and for our approach. Note: the AESC report discounts future benefits a 1.36% annually. To be consistent with the AESC report, in this figure we report results based on a re-calculation of our capacity values using a 1.36% annual discount rate instead of our 4% base case discount rate.

Finally, we update the existing benefit to cost ratios of natural gas energy efficiency programs in New England using our results. For reference, efficiency programs with a benefit to cost ratio greater than one can be considered cost effective and thus Public Utility Commissions can allow or require utilities to implement those programs. We use Equation 3.3 to update the benefit to cost ratio of natural gas efficiency programs to account for the benefits we estimate with our method. In Equation 3.3: r_{AESC} is the benefit to cost ratio of the efficiency program from the AESC report, b_{AESC} represents the benefits of the efficiency program reported in the AESC report, and b_2 represents the benefits we estimated in this paper. We derive Equation 3.3 in the Appendix Section 8.13. For example, Massachusetts reports that the average benefit to cost ratio for Commercial and Industrial natural gas efficiency programs is 2.31:1 [59]. The 2013 AESC report estimates that space heating programs in southern New England avoid \$6.6 per MCF (no retail margin avoided). Using our estimate of total avoided costs (\$2.2 per MCF), the updated benefit to cost ratio for space heating programs is 0.7:1.0. This suggests that many individual natural gas space heating efficiency programs in southern New England may not be cost effective when the cost effectiveness test considers the resale value of excess capacity.

$$r_2 = \frac{b_2}{b_{AESC}} * r_{AESC} \tag{3.3}$$

On the other hand, water heating efficiency programs in Massachusetts remain cost-effective when we account for the opportunity cost of avoiding firm pipeline capacity purchases. Further, Liberty Utilities, the largest natural gas utility in New Hampshire, reports current benefit to cost ratios of around 1.5:1.0 [80]. Our results suggest that the avoided costs of space heating natural gas efficiency programs in New Hampshire may exceed 2.0:1.0 when the cost effectiveness test considers the resale value of excess capacity. Based on these findings, we recommend that Public Utility Commissions further explore the merit of including the capacity status of utilities and the resale value of excess capacity in the cost effectiveness testing framework.

Sensitivity analysis

We assess the changes in our results as we vary 1) the value of short term capacity resale, 2) the price of firm pipeline capacity, 3) the number of days that utilities use off-system peaking resources, and 4) the assumed discount rate.

We vary the value of short-term capacity resale because a utility may not receive the market rate for short-term capacity. For example, a utility may allow large customers to purchase the utility's excess capacity at a pre-negotiated rate (i.e. interruptible transportation service). Other utilities may have capacity management agreements where third parties sell the utility's excess capacity and keep a portion of the revenue. Further, natural gas markets are constantly evolving and current short-term capacity prices may change in the future. For example, the value of short-term pipeline capacity may decrease due to the construction of new transmission pipeline capacity or changes in the price of liquefied natural gas imports. We vary the price of firm pipeline capacity because utilities report a range of prices that they have paid or expect to pay for new capacity. Finally, we vary the number of days that utilities use off system peaking resources because the AESC report states that this number is approximate. Finally, we vary the discount rate used because public utility commissions may choose to use a discount rate different from the 4% used in our base case analysis (e.g. Connecticut [60]).

All natural gas efficiency programs are sensitive to the value of short-term capacity resale (Figure 3.4). Indeed, this is the most sensitive parameter in our analysis. Additionally, for utilities in southern New England (i.e., utilities that face a firm capacity shortfall), the price of new firm capacity is the second most sensitive parameter in our analysis. If Public Utility Commissions decide to consider the amount of revenue that utilities receive through capacity resale in the cost effectiveness testing framework, we recommend they work with utilities and other stakeholders to appropriate quantify the revenue utilities would collect for selling an additional unit of excess capacity (i.e. the marginal value of excess capacity resale).

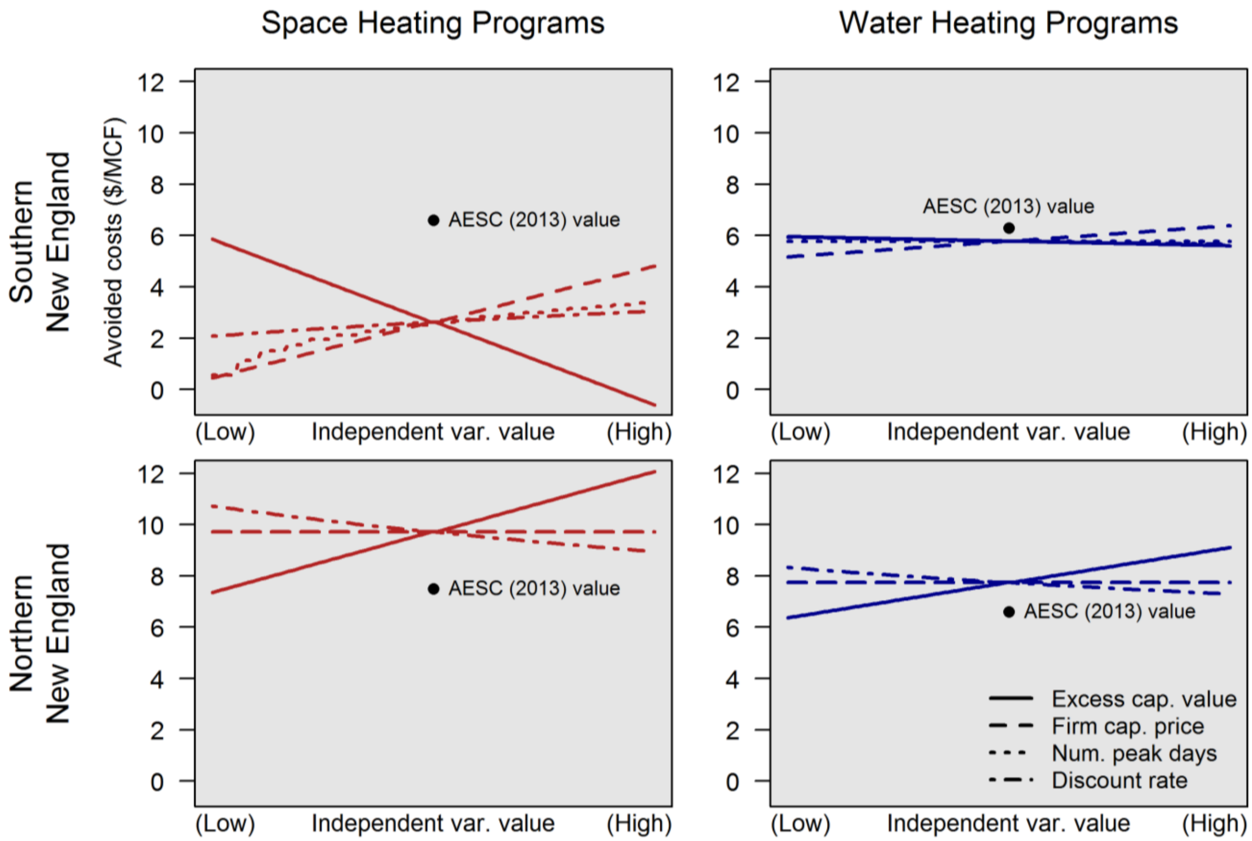

Figure 3.4. Spider plots for each New England region and for each type of natural gas efficiency program. Each plot shows the sensitivity of the costs avoided by the efficiency program (assuming $5 per MCF natural gas commodity costs) over a range of input values for four independent variables: spot natural gas price difference between the Dominion South pricing point and the Algonquin Citygates pricing point ($/MCF; solid line, see note below), the cost of firm pipeline capacity (0.2 – 0.66$/CF-y; wide dashed line), the number of days the utilities uses off system peaking resources (0 – 20 days; narrow dashed line), and the discount rate (1 – 7%; alternating wide and narrow dashed line). Note: the difference between the Dominion South and Algonquin Citygates pricing points varies throughout the year. Table 4 in the Methods shows the range of spot price differences for the base case (0.3, 14 $/MCF), the lowest spot price difference we test (0.1, 6.9 $/MCF) and the high spot price difference we test (0.4, 20 $/MCF). We scaled the base case (NYMEX futures data) linearly to arrive at the low and high spot price difference scenarios. These spot price differences translate into average excess capacity resale revenues from $1 (low spot price difference) to $2.9 (high spot price difference) per MCF of space heating program savings and $0.7 to $2.3 per MCF of water heating program savings in Southern New England. For Northern New England, these spot price differences translate into average excess capacity resale revenue from $2.4 to $7.1 per MCF for space heating programs and $1.4 to $4.1 per MCF for water heating programs.

3.5 Conclusions

Natural gas utilities in New England increasingly act as a central component of the New England energy system. Natural gas utilities both meet the demand of natural gas consumers and resell excess pipeline capacity to natural gas-fueled electricity generators. Recent periods of pipeline congestion, high natural gas and electricity prices, and controversial infrastructure proposals have increased the public and policymaker scrutiny of the status quo.

In order to help inform the debate of New England's energy system options, we re-estimate the benefits of natural gas end-use efficiency programs for utilities in New England. In particular, we model how efficiency programs affect utility firm pipeline capacity purchases and the excess capacity that utilities resell in the short-term capacity markets (i.e. the "capacity value" of the efficiency program). Our research extends the current literature by incorporating both the capacity shortfall status of the utility and the monetary value of reselling excess capacity into the cost effectiveness testing framework.

We find that when the utility currently owns sufficient pipeline capacity to meet demand projections, the capacity value of natural gas energy efficiency measures is high because implementing an efficiency program allows the utility to resell additional excess capacity in the high-value short-term resale market: \$4 to \$5 per thousand cubic feet (MCF) of natural gas savings over the life of the space heating efficiency program and \$3 per MCF for water heating efficiency programs. When the utility needs to purchase additional firm pipeline capacity to meet projected demand growth, the efficiency program may avoid part of the planned purchase but also resells less excess capacity. For this scenario, the capacity value of space heating efficiency programs is approximately -\$2 to -\$3 per MCF of natural gas savings, and \$1 per MCF for water heating efficiency programs.

Given the current capacity situation of utilities across New England, our findings suggest that some existing natural gas efficiency programs in southern New England (CT, MA, RI) may not be cost effective while a greater number of natural gas efficiency programs in northern New England (ME, NH) may be cost effective. The capacity value of natural gas efficiency programs, and thus the cost effectiveness of these programs, is sensitive to the revenue that utilities receive when they sell excess capacity in the short term market.

We recommend that public utility commissions consider including the revenue that utilities receive from reselling excess capacity in the cost effectiveness testing framework for efficiency programs. PUCs could accomplish this by valuing excess pipeline capacity at the basis differential between New England and production areas or by working with utilities and other stakeholders to identify a mutually agreeable value.

4 Quantifying the Benefits and Costs of Distributed Solar Photovoltaics for Electricity Ratepayers in Portugal

This chapter is a work in progress. The current citation is:

Gilbraith, N.; Carvalho, P.M..S., Azevedo, I.L., 2015. Quantifying the benefits and costs of distributed solar photovoltaics for electricity ratepayers in Portugal. Working paper.

4.1 Abstract

In 2008, the European Parliament adopted the European Commission's (EC) "20-20-20" goals in order to address global climate change concerns and to tap the potential economic and energy security benefits of energy systems based on renewable energy resources. Under the 20-20-20 package, Portugal needs to produce 60% of total electricity using renewable energy sources (or RES) by 2020. However, the total cost of subsidy policies that lead this transition now account for approximately 33% of residential consumers electricity bills. In light of both the 20-20-20 climate goals and the increasing need to achieve these goals in a cost effective manner, we quantifying the benefits and costs of distributed solar PV in Portugal for panel owners, ratepayers as a whole, and the specific group of ratepayers that does not own solar panels. We measure the benefits and costs of distributed solar PV from these perspectives by computing and comparing the present value of the cost of a distributed solar PV array, the present value of grid electricity purchases that solar panel owners avoid, and the present value of grid generation and delivery costs that the grid avoids when panel owners consume less electricity. We find that solar PV is net present value positive for the average Portuguese electricity ratepayer that owns a solar

array. The most attractive option for an average consumer is a 500W array, with a net present value of 700-800€ relative to a present cost of about 1500€. On the other hand, distributed solar PV generation has a higher cost than using the grid to produce and deliver a marginal unit of electricity during periods that solar PV arrays generate electricity. Ratepayers as a whole pay 900-2600€ more in total costs for each kilowatt of distributed solar PV capacity that panel owners install; the 500 W solar array increases total system costs by 1600€. Further, panel owners also avoid paying sunk grid costs, such as revenue guarantees to other renewable generators and the costs of grid infrastructure. In order to recover these sunk costs from ratepayers, retail prices will increase for all consumers. As a result, non-panel owners will pay an additional 1600€ in bills (total across all non-panel owners) for each 500W array that panel owners install. This is equivalent to a 140€/MWh subsidy to panel owners, which is larger than the subsidy that many other Portuguese generators receive but smaller than the subsidy for existing solar PV arrays. Portuguese policy-makers could reduce this subsidy by instituting some type of solar PV fee (more straightforward) or changing the rate structure such that retail prices more closely reflect underlying costs (more complex). Alternatively, Portuguese policy makers could maintain the existing policy. The subsidy per unit of installed solar PV will not change; however, the large number of consumers that live in multi-family housing (and may not be able to install solar PV) suggests that the total value of the subsidy from panel owners to non-panel owners will remain limited.

4.2 Introduction

In 2008, the European Parliament adopted the European Commission's (EC) "20-20-20" goals in order to address global climate change concerns and to tap the potential economic and energy security benefits of energy systems based on renewable energy resources. The 20-20-20 package aims to reduce European Union (EU) greenhouse gas emissions by 20% relative to 1990, meet 20% of primary energy demand with renewable resources, and improve the energy efficiency of the EU by 20%.[103] The European Commission (EC) expects that four policy thrusts will enable the achievement of the 20-20-20 policy goals: a greenhouse gas (GHG) cap and trade program (i.e., the EU Emissions Trading System or ETS), binding national targets for greenhouse gas emissions that fall outside the scope of the EU ETS, binding national renewable energy targets, and further efforts to spur the use of carbon capture and storage.[103–106]

As an EU member state, Portugal participates in the 20-20-20 policy package. Under the 20-20-20 package, Portugal needs to produce 60% of total electricity using renewable energy sources (or RES) by 2020.[107] For reference, renewable energy resources met less than one third of Portuguese electricity demand in the early 2000s, but as we explain below that changed substantially over the course of this last decade.[108,109] Neither the EU ETS nor the binding national emission reduction target (a 1% increase in emissions between 2005 and 2020 for Portugal[104,110]) have attracted substantial attention or concern from policymakers. This is likely due, in part, to the economic crisis and that emissions caps and reductions are based on pre-crisis emissions projections. Further, Portugal does not have any active or planned carbon capture and storage projects.[111,112]

In order to meet its ambitious renewable electricity targets, Portugal was also among the first, and multiple, EU member states that established substantial subsidies to spur investments in renewable energy sources. For example, the Portuguese government maintained feed-in-tariffs for wind powered generators at about 100 €/MWh between 2001 and 2012 despite steady reductions in the levelized cost of wind energy.[113–115] Due to this dynamic, wind energy investments became profitable to independent power producers (IPPs) in Portugal during the late

2000s.[113] Additionally, in 2007, the Portuguese government established subsidies for the installation of distributed renewable energy sources and co-generation facilities. The initial subsidies guaranteed solar PV generation 630 €/MWh for the first eight years of the system's lifetime.[116] The net present value of the feed-in-tariff remained above 4 €/W[1] of installed capacity until 2012 because, while the government reduced the feed-in-tariff over time, the government also increased the duration of the feed-in-tariff from eight to fifteen years.[117–119] For reference, the EU Joint Research Center estimates that the installed price of residential solar PV in Germany fell below 4 €/W in 2008.[120] Finally, the Portuguese government also made administrative changes that streamlined the registration and connection process for small distributed energy resources.[116]

The renewable energy subsidies and administrative changes resulted in rapid changes in the Portuguese electricity mix. In 2000, the Portuguese electricity grid was dominated by large hydroelectric and thermal power plants. The installed capacity of hydro and thermal power plants were about 4.5 GW and 5.5 GW, respectively, and thermal power plants met around two-thirds of total demand.[109] After rapid investment in wind power throughout the 2000s, by 2013, Portugal boasted 4.4 GW of wind energy capacity.[121] These wind generators satisfied 24% of total electricity demand.[121] In fact, hydro, wind, and solar power met a combined 52% of Portuguese electricity demand in 2013, a value that approached Portugal's 2020 target of 60% renewable based electricity.[121] The fraction of total demand met by thermal generators, including some cogeneration facilities and a small amount of biomass based cogeneration, fell to 43%.[121] When we normalize wind and hydro output based on long term average capacity factors, however, hydro, wind, and solar power would only meet 45% of total demand in an average

[1] Authors' calculations based on 1,600 kWh of generation per year (18% capacity factor) and a 6% discount rate on future benefits.

year.[121] Thus, if Portugal wants to meet the 2020 renewable energy targets, then it needs to continue to invest in strategies that displace fossil-based electricity generation, including increasing the installed capacity of renewable energy resources.

However, the total cost of subsidy policies grew rapidly and now accounts for a significant fraction of total electricity system costs. For example, Portuguese ratepayers paid 133 million Euro in 2000 to cover general economic and policy costs ("custos de interesse económico geral"). In 2015, the Portuguese electricity system regulator (Entidade Reguladora dos Serviços Enertéticos; ERSE) projects that Portuguese ratepayers will pay over 2 billion Euro to cover general economic and policy costs.[122] Renewable generators are directly collect over 1.3 billion Euro of these expenditures, and are indirectly responsible for some fraction of the remaining total[2].[122] As a result of the rapid increase in general economic and policy expenditures, the "global system fee", which is the primary vehicle for collecting general economic and policy costs, will be 0.063 €/kWh for low-voltage consumers (e.g. residential consumers) in 2015.[122] This is about one-third of the average low-voltage electricity tariff and is now the largest component of the low-voltage tariff.[122] Further, the Portuguese government has not allowed ERSE to recover the total amount of revenue promised to all electricity system participants and thus a tariff deficit began to accrue in 2007.[123] ERSE projects the cumulative tariff deficit will be 5.1 billion Euro at the end of 2015, or 82% of the total amount of money that the electricity system will collect from all ratepayers in 2015.[122]

[2] The Portuguese government established, through feed-in-tariffs, the minimum revenue that subsidized generators would receive (€/MWh). Renewable such as wind depress wholesale electricity prices (sometimes called the merit order effect [163,164]), which increases the difference between guaranteed revenues and the market price of electricity. Thus, the total cost of subsidies to other, non-renewable, subsidized generators increases as a result of the increasing penetration of renewables.

Portugal is not unique in terms of struggling with the cumulative price of sustained subsidy policies. For example, in Germany, renewable feed-in-tariffs have been blamed for increasing consumer electricity costs, decreasing the profitability of electric utilities, and occasionally causing imbalances between electricity supply and demand.[124–126] Spain, which successfully incentivized large investments in renewable energy, also faces a large tariff deficit.[127]

The high price of renewable energy subsidies and the economic crisis caused the Portuguese government to rapidly adjust subsidy policies. Beginning in 2010, the Portuguese government began scaling back the subsidies offered to consumers for the installation of small distributed generators such as solar panels. By 2014 the value of the solar PV subsidy was, apparently, less than the price of solar PV systems: consumers only installed 17 kW of subsidized solar PV capacity relative to the quota of 11.5 MW.[128] For reference, applications for the solar PV subsidy exceeded the capacity quota through 2012.[128] Additionally, in 2012, the Portuguese government suspended new interconnection permits for large renewable energy generators such as wind turbines.[129] Finally, the Portuguese government scaled back planned hydro capacity expansions from 1,100 MW (in 2007) to 260 MW.[109,130,131]

The increasing price of renewable energy subsidies also spurred a renewed focus on the "cost effectiveness "of renewable energy support schemes. For example, a European Commission progress report on the penetration of renewable energy resources found that the large subsidies and rapid capacity installation rates between 2008 and 2012 were not high enough to meet 2020 targets but still discussed the need to improve the cost effectiveness of subsidies.[132] More recent European Commission guidance focuses on how to avoid over-compensating renewable energy generators.[133] The most recent distributed generation policy update in Portugal also discussed the need to ensure Portuguese consumers can purchase reasonably priced energy.[134] The fact that renewable's subsidies may be increasing electricity system costs is further concerning because evidence from California suggests that that the private individuals that adopt solar PV have incomes above the median income of electricity consumers.[135] Thus renewables subsidies could potentially be increasing electricity costs for average and below average income consumers while cutting electricity costs for above average income consumers.

In light of both the 20-20-20 climate goals and the increasing need to achieve these goals in a cost effective manner, it is necessary to fully characterize the benefits and costs of renewable energy within European energy systems. We contribute to this task by quantifying the benefits and costs of distributed solar PV in Portugal, which serves as our case study due to the high solar resource potential in Portugal and rapidly evolving policy landscape. Specifically, 1) we assess whether the current distributed generation policy (Decreto-Lei 153/2014) is likely to spur consumer adoption of distributed solar PV, 2) quantify the net cost effectiveness of distributed solar PV for ratepayers (i.e. compare benefits and costs across all ratepayers), and 3) quantify the magnitude of implicit or explicit subsidies that panel owners receive for installing a solar PV array, which may accrue as a wealth transfer from non-panel owners to panel owners.

The rest of the paper is organized as follows: in Section 4.3 we explain the methods and data; in Sections 4.4 and 4.5 we report the results of our research and sensitivity analysis and; in Section 4.6 we provide conclusions and policy recommendations.

4.3 Methods

We assess these questions using a framework that allows us to consistently quantify the benefits and costs of solar PV to panel owners, ratepayers as a whole, and the specific group of ratepayers that do not own solar panels. We take a technical approach to solar PV policy, i.e. quantifying the benefits and costs of solar PV adoption, rather than a behavioral approach to solar PV policy, i.e. quantifying how consumers will react to a given policy, for several reasons. Given Portugal's, and the European Union's climate goals, Portugal should make efforts to quantify the benefits and costs of different approaches that may reduce carbon dioxide emissions. In creating these technical estimates of benefits and costs, Portugal can evaluate the value of achieving energy systems change using various pathways. Second, technical estimates form the backbone of an integrated technical and behavior model of a given policy. Behavioral research is an important endeavor to estimate how much change a given policy is likely to achieve. However, technical models of the energy system are critical in order to interpret the effects of the policy-driven change. Thus our research will provide an important value of Portuguese policy makers: how will solar PV affect energy system costs, panel owner electricity costs, and non-panel owner electricity costs.

First, if the present value of the cost of installing and operating a distributed solar PV array is less than the present value of purchasing the same electricity from the grid, then the panel owner has a monetary incentive to adopt solar PV (Table 4.1; Equation 4.1a). Equation 4.1b adds 'zero' to the first equation and shows we can interpret the panel owner benefit of a solar array as the difference between providing electricity using the grid and a distributed solar array plus the difference between the cost of using the grid to generate and deliver an additional unit of electricity and the price the consumer pays for that electricity (e.g. the panel owner may avoid paying sunk grid costs).

From the overall ratepayer perspective, if the present value of the cost of installing and operating a distributed solar PV array is less than the present value of the cost of generating and delivering the same electricity via the grid, then the electricity system becomes more cost-effective due to solar PV (Equation 4.2).[135] Comparing Equations 4.1 and 4.2, we see that the private incentive to adopt distributed solar PV, which is based on the cost of solar and retail prices, may diverge from the overall ratepayer incentive to adopt solar PV, which is based on the cost of solar and the cost of grid electricity. The reason for this divergence is because electricity rates (prices) do not reflect underlying costs.[136–138] Regulators often set retail prices based on "average costs", which include sunk costs for grid infrastructure and investments, and not marginal costs.[136] Further, regulators often intentionally maintain similar retail prices for consumer groups with different underlying costs of service, i.e. intentionally allow cross-subsidization across consumer groups.[138]

To quantify the wealth transfer from non-panel owners to panel owners, we first assume that regulators will allow prices to change (e.g. year to year) to ensure that ratepayers pay all electricity system costs. Then, the wealth transfer from other ratepayers to panel owners is the difference between the panel owner's net present value and the overall ratepayer net present value (Equation 4.3a). This is also equal to the reduction in grid costs when the panel owner reduces their electricity demand minus the price the panel owner would have paid for that electricity (Equations 4.3b). Non-panel owners pay (or receive) this difference because electricity rates will increase (or decrease) to maintain an electricity system such that total ratepayer bills equal total costs.[135,136] Non-panel owners also pay the standard 23% value added tax on increases in electricity rates. The Portuguese electricity regulator already reports that reductions in demand contributed to tariff growth between 2010 and 2014, which validates that this mechanism actually occurs.[139–142]

Table 4.1. The equations we use to calculate the value of solar to three important electricity system stakeholders: panel owners, all ratepayers, and other ratepayers that do not own solar panels. For consistency, throughout the manuscript we define costs (i.e. the cost of the solar array and the costs of grid electricity) and grid electricity (i.e. the price of grid electricity purchases) as having positive values (i.e. the consumer or grid expenditure). Thus if consumer expenditures go from 50€ to 30€, the net present value of the intervention is 20€.

$$NPV(owner) = PV\left(price_{grid}\right) - PV(cost_{solar}) \tag{4.1a}$$

$$NPV(owner) = \left(PV\left(cost_{grid}\right) - PV(cost_{solar})\right) + \left(PV\left(price_{grid}\right) - PV\left(cost_{grid}\right)\right) \tag{4.1b}$$

$$NPV(overall) = PV\left(cost_{grid}\right) - PV(cost_{solar}) \tag{4.2}$$

$$NPV(overall) = NPV(owner) + NPV(others) \tag{4.3a}$$

$$NPV(others) = PV\left(cost_{grid}\right) - PV\left(price_{grid}\right) \tag{4.3b}$$

Thus we observe that the value of solar PV to different ratepayers depends on the relative magnitude of the three relevant quantities we describe above, which are the present value of solar PV costs, the present value of grid electricity purchases, and the present value of grid generation and delivery costs. Table 4.2 shows the possible permutations of these quantities and their effects on each stakeholder group. In the remainder of the methods, we describe how we estimate each quantity.

Table 4.2. The rows of this table show the permutations of the relative values of the three variables that determine the value of solar for each ratepayer group. Column one shows the value of solar to panel owners, column two shows the value for non-panel owners, and column three shows the value for all ratepayers. As a reference, we also show the conditions for which panel owners, other ratepayers, and ratepayers overall realize positive benefits from distributed solar PV.

Permutation	Panel owner benefit	Other ratepayer benefit	Overall ratepayers benefit
	$PV(cost_{solar}) < PV(price_{grid})$	$PV(price_{grid}) < PV(cost_{grid})$	$PV(cost_{solar}) < PV(cost_{grid})$

<table>
<tr>
<td>$PV(cost_{solar}) < PV(price_{grid}) < PV(cost_{grid})$</td>
<td rowspan="3">Positive
The price of purchasing electricity from the grid is greater than the cost of the demand side intervention.</td>
<td>Positive
The cost of providing electricity to the panel owner via the grid is greater than the price for consuming it.</td>
<td rowspan="2">Positive
The marginal cost of providing electricity to the panel owner via the grid is greater than the marginal cost of the demand side intervention.</td>
</tr>
<tr>
<td>$PV(cost_{solar}) < PV(cost_{grid}) < PV(price_{grid})$</td>
<td rowspan="3">Negative
The cost of providing electricity to the panel owner via the grid is less than the price for consuming it. If panel owners reduce demand during periods when <u>prices (i.e. average costs) exceed costs</u>, then the new average cost (i.e. price) will be higher for all consumers.</td>
</tr>
<tr>
<td>$PV(cost_{grid}) < PV(cost_{solar}) < PV(price_{grid})$</td>
<td rowspan="3">Negative
The marginal cost of providing electricity to the panel owner via the grid is less than the marginal cost of the demand side intervention.</td>
</tr>
<tr>
<td>$PV(cost_{grid}) < PV(price_{grid}) < PV(cost_{solar})$</td>
<td rowspan="3">Negative
The price of purchasing electricity from the grid is greater than the cost of the demand side intervention.</td>
</tr>
<tr>
<td>$PV(price_{grid}) < PV(cost_{grid}) < PV(cost_{solar})$</td>
<td rowspan="2">Positive
The cost of providing electricity to the panel owner via the grid is greater than the price for consuming it. If panel owners reduce demand when <u>costs exceed prices (i.e. average costs),</u> then the new average cost (i.e. price) will be lower for all consumers.</td>
</tr>
<tr>
<td>$PV(price_{grid}) < PV(cost_{solar}) < PV(cost_{grid})$</td>
<td>Positive
The marginal cost of providing electricity to the panel owner via the grid is greater than the marginal cost of the demand side intervention.</td>
</tr>
</table>

Present value of the cost of installing and operating a distributed solar PV array.

The private cost of a solar PV array is the present value of capital cost of the array plus tax and loan interest. Portugal only had slightly over 200 MW of solar PV at the end of 2013 and therefore we judge it is difficult to generalize installed solar PV prices.[121] However, we identify several existing vendors of small solar PV arrays that comply with the sizing and connection requirements of Decreto Lei 153/2014. For example, vendor information suggest that the price of 200W arrays is between 400€ and 700 € (3.2 €/W) and the price of 500W arrays is between 600 € and 1,100 € (2.2 €/W), excluding the 23% value added tax (Appendix Section 9.1). The costs cited above include the panels, inverters, and electronic components. Several vendors offer separate installation service that costs from 150 – 400 €. Table 4.3 shows the combined array and installation costs we use in the baseline. Given that the current market for solar PV in Portugal is small, solar PV prices vary between locations and across time, our review of array prices was not exhaustive, we also vary the price of the solar PV array in the sensitivity analysis.

Table 4.3. Our judgment of representative prices of purchasing and installing a distributed solar PV array in Portugal.

Array size	Capital costs, installed, excl. tax	Capital costs, installed, (€/W)
200W	600 €	3 €/W
500W	1100 €	2.2 €/W
1000W	1800 €	1.8 €/W
1500W	2300 €	1.5 €/W

In the base case we assume the panel owner pays for the system using a loan with a 5% real interest rate and fifteen (15) year duration. We assume the panel owner has a 5% real discount rate, and inflation is 2% per year.[3] Equation 4.4 defines the present value of the cost of the solar array. '$PV(cost_{solar})$' is the present value of the cost of the solar array, 'N' is the system and loan lifetime, 'c' is the array cost in Euro, 'r' is the value-added-tax rate, 'i_L' is the nominal loan interest rate, 'd' is the nominal discount rate, and 'n' is the annual time index.

[3] The nominal interest and discount rate are: $rate_{nom} = (1 + rate_{real}) * (1 + inflation) - 1$. A simple sum of the two rates provides an adequate approximation, i.e. 5% + 2%.

$$PV(cost_{solar}) = \sum_{n=1}^{N} \left(c \times (1+r)\right) \left(\frac{i_L(1+i_L)^N}{(1+i_L)^N - 1}\right) \left(\frac{1}{(1+d)^n}\right) \quad (4.4)$$

Present value of the avoided grid electricity purchases

Since 2001, several laws established and re-iterated that the utility is required to purchase all electricity generated by consumer owned solar panels at the prevailing feed-in-tariff.[116,117] In 2013, the Portuguese government reduced the feed-in-tariff to an unattractive level and consumer applications for the feed-in-tariff decreased to almost zero.[128] The new distributed generation policy (Decreto-Lei 153/2014) replaces the effectively defunct feed-in-tariff scheme with remuneration based on "self-consumption" and excess generation resale. Decreto-Lei 153/2014 essentially provides the consumer with a marginal electricity price that varies based on the level of demand of the consumer (Figure 4.1).

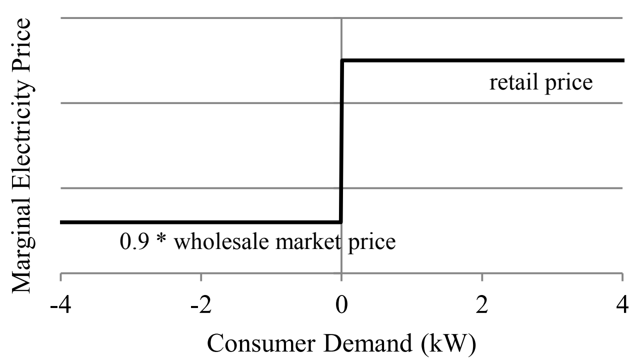

Figure 4.1. Illustrative diagram of the marginal retail electricity price that a distributed solar PV array owner faces.

During periods that the solar array generates electricity and that generation offsets consumer demand, PV generation displaces consumer purchases from the grid (i.e. "self-consumption"). The monetary benefit of avoiding grid purchases equals the prevailing residential retail electricity tariff plus applicable taxes. The 2014 retail tariff varies between 0.095 €/kWh and 0.305 €/kWh, depending on the time-of-use period and consumer tariff (Appendix Section

9.3, Figure 9.8), excluding the 23% value added tax on electricity.[134] In our analysis, we assume that real electricity prices grow at 2% annually[143].

Decreto-Lei 153/2014 also allows panel owners, if they choose, to resell electricity production in excess of household electricity demand to the grid for 90% of that month's average wholesale electric energy market price.[134] Monthly average wholesale market prices between 2010 and 2015 were between 0.031 and 0.054 €/kWh. However, the policy specifies that reselling excess generation requires additional inspections, permitting fees, and metering infrastructure. Therefore, we evaluate two scenarios: 1) the panel owner both self-consumes and resells excess electricity generation to the grid and 2) the panel owner self-consumes and injects electricity into the distribution grid but does not receive any compensation for these injections.

Table 4.4. The equations we use to calculate the panel owner (i.e. private) monetary benefit '*b*' of each unit of solar PV generation. Where: '*g*' is solar panel generation, '*q*' is panel owner electricity demand without considering solar PV, '*T*' is the residential retail tariff including tax, '*LMP*' is the Portuguese wholesale electric energy price, the subscript '*h*' is an hourly time index, the subscript, 'i_T' is the nominal electricity tariff growth rate, 'i_M' is the nominal wholesale market price growth rate, and the subscript '*m*' is a monthly time index.

Condition	Value
$g_h \leq q_{h,i}$	$b_{h,n} = g_h T_h (1 + i_T)^n$
$g_h > q_{h,i}$	$b_{h,n} = \begin{Bmatrix} q_{h,i} T_h (1 + i_T)^n + (g_h - q_{h,i})(0.9 \times \overline{LMP_m}(1 + i_M)^n) \\ 0 \end{Bmatrix}$

We compute whether panel owners self-consume or inject PV generation into the grid based on the coincidence of residential electricity demand and solar array generation. To model solar PV generation, we use an established model from the literature that considers the effect of solar irradiance and panel temperature on solar panel output. [144,145,146] In turn, panel temperature varies as function of solar irradiance, ambient temperature, wind speed, and array installation parameters.[144,145] We further assume that the performance ratio, or the amount of electricity that is successfully converted from DC to AC power, is 0.8.[147] Finally, we assume panel efficiency degrades at 0.5% annually.[148] We provide additional modeling details in the SI. We assume the array is in Lisbon, Portugal and therefore we use meteorological data for solar irradiance, ambient temperature, and wind speed from the University of Lisbon's Instituto Superior Tecnico meteorological station. The University of Lisbon meteorological station provides single minute measured readings from April 2012 through September 2014 for solar irradiance, ambient temperature and wind speed.[149] We average these data hourly. We assume the array faces directly south at an incline of 30°.

To model residential electricity demand, we use an average Portuguese residential (i.e. low voltage) electricity load profile.[146] We also perform a sensitivity analysis in which we introduce noise into the average load profile, which we expect to better reflect the variable natural of household electricity demand, and recalculate the benefits and costs of solar PV.[150]

We model the benefits and costs of solar PV for multiple array sizes below 1.5kW in this research. We do not model arrays above 1.5 kW based on the permitting and certification cutoffs present in Decreto Lei 153/2014, which we discuss in the Appendix Section 9.4.[134] Equation 4.5 shows the present value of grid electricity purchases that the panel owner avoids.

$$PV\left(price_{grid}\right) = \sum_{n=1}^{N} \left(\sum_{h=1}^{8760} b_{h,n}\right)\left(\frac{1}{(1+d)^n}\right) \tag{4.5}$$

Present value of the cost of grid electricity that solar PV displaces

We quantify the avoided short- medium- and long-run electricity system costs that solar PV arrays in Portugal will avoid. Baker et al. (2013) review the short-, medium-, and long-run economics of solar PV. They report that in the short-run, the value of solar PV to the electricity system is the avoided electricity system costs plus avoided emissions costs. Equation 4.6a shows the short-run costs that solar PV avoids, excluding the social benefits of avoided pollutant emissions. '*V*' is the total value of solar PV which is a function of '*K*', the quantity of solar PV on the grid. 'C' is total grid costs as a function of demand ('y'). Solar panels produce quantity 'g' of electricity for each unit of solar PV. 'h' is an hourly time index. We replace the U.S. specific estimates of theoretically avoidable electricity system costs in Baker et al. (2013) with Portugal specific estimates that we discuss below. The value of a marginal unit of solar PV is the derivative of the value of solar with respect to 'K' (Equation 4.6b), which we obtain by differentiating Equation 4.6a using the chain rule. Thus the short-run value of a unit of solar PV is the solar PV generation in each hour multiplied by the marginal change in system costs with respect to load in that hour and then summed over the entire year. Since we evaluate the rate impacts of solar PV, we do not include the health and environmental benefits of reducing pollutant emissions. However, we discuss these in the Discussion.

$$V(K) = \sum_{h}^{H} C(y_h) - \sum_{h}^{H} C(y_h - g_h K) \tag{4.6a}$$

$$\frac{dV(K)}{dK} = \sum_{h}^{H} g_h \times C'(y_h - g_h K) \tag{4.6b}$$

Marginal changes in electricity system costs can be reductions in energy costs (i.e. variable generator costs), transmission and distribution line losses, and environmental compliance costs, among others. Theoretically, in competitive energy only electricity markets such as Portugal, the locational marginal price appropriately values the cost of the last unit of electricity demand, including variable generator costs, transmission losses, and internalized environmental compliance costs.[151] However, Portuguese energy policies provide revenue guarantees to over 80% of generation in Portugal and therefore disconnect the economic cost of generating and delivering and additional unit of electricity from the wholesale market price.[152] The total value of these out of market payments has been in the billions of Euros each year since 2008.[122,139–142,153–155] Since the revenue guarantees are binding, we judge that the wholesale market price is not an accurate indicator of the true cost of a marginal change in electricity demand.

In place of wholesale market prices, we estimate the marginal cost of grid electricity by quantifying marginal generation costs and transmission and distribution losses during periods that solar PV generates electricity. We assume that the grid will react similarly to new non-dispatchable generation (e.g. distributed solar) as it has reacted to the growth in non-dispatchable generation from 11 TWh in 2005 to 28 TWh in 2013. Our first-order assessment of effect of decreasing net demand (i.e. total demand minus non-dispatchable generation such as solar) on dispatchable generation indicates that a) imports are the only dispatchable generation resource that show a statistically significant decline when net demand decreases and b) over the past several years, imports, coal, natural gas, and oil + other fired generators all supplied less electricity than in 2005. We show these analyses in Appendix Section 9.9. To overcome the uncertainty of which type of generator that solar PV generation will displace, we summarize the avoidable costs of each class of electricity generator below and then parameterize the avoided generation costs in our solar PV valuation model:

- Legacy power purchase agreements ("Contratos de Aquisição de Energia (CAE)"). CAE agreements specify that the generator will recover its fixed plus variable expenditures, including emissions compliance costs.[156] When solar PV generation displaces a generator with a revenue guaranteed contract, the fixed expenditures of the generator do not change. The variable expenditures of the generator decrease by the marginal cost of producing a unit of electricity. Two companies chose to keep their legacy power purchase agreements when Portugal transitioned to a competitive wholesale electricity market. These companies are Tejo Energy with around 600 MW of primarily coal fired electric capacity, and Turbogás with around 1,000 MW of natural gas combined cycle capacity. The Portuguese electricity regulator reports that between 2012 and 2015(projections), the variable price of electricity are 29 – 46.3 €/MWh (Tejo Energia) and 65.6 – 75.8 €/MWh (Turbogás). These prices vary with market conditions.[157–160]

- Contracts to replace legacy power purchase agreements ("Custos para a Manutenção do Equilíbrio Contratual (CMEC)"). CMEC contracts specify that total generator revenues over the generator's lifetime will achieve a pre-determined present value.[161] Thus, solar PV can only reduce CMEC generator revenues if solar PV generation displaces a CMEC generator after the generator has recovered its revenue guarantee and is making extra profits. Market revenues have not provided CMEC generators will their full guaranteed annuity since 2008 and therefore displacing CMEC generators will not avoid any generation costs.[122,139–142,153–155]
- Special regime generators (mostly wind and co-generation facilities) have special grid access priority and are "must take" by the system.[162] Therefore, we assume that solar PV generation will not displace special regime generators.
- If solar PV generation displaces a generator that receives all its revenue from the wholesale market, then the generator loses revenue equal to the market price of

electricity. From 2011 through 2014, daytime (10am – 6pm) hourly wholesale market prices averaged 48 €/MWh with a standard deviation of 16 €/MWh; prices exceeded 100 €/MWh in 8 hours (Appendix Section 9.8).[143] Given that Portuguese policies provide revenue guarantees for most Portuguese generators, we do not include any additional short-run benefits from the 'merit-order effect'.[152] The 'merit-order effect' occurs when low variable cost resources, such as solar PV, displace higher cost resources in a competitive energy market and thus drives down the market price of electricity that all generators receive.[163–165]

- If solar PV displaces imports from Spain, the Portuguese will transfer less money to the Spanish electricity system. Energy market prices between Portugal and Spain generally do not exhibit a difference of more than several Euro per megawatt hour. Thus, we assume avoiding imports will avoid electricity purchases at the Portuguese market rate.

Solar PV generation can also reduce distribution and transmission network losses by replacing centralized generation with generation near the point of use.[166,167] Solar PV reduces network losses most effectively when PV generation is coincident with demand.[166,167] However, if solar array output exceeds electricity demand on that section of the network, solar PV can increase network losses.[125,166] A KEMA study that focuses on Portugal found that solar array output is not coincident with Portuguese peak electricity, but that if the penetration of solar PV is low, then PV generation is likely to reduce network losses. Therefore, we assume that each unit of solar PV generation avoids the 10% average distribution system loss rate.[168–170] This is an upper bound on average distribution system losses since these loss statistics include "non-technical" losses (i.e. electricity theft), which is a concern in Portugal.[122] Additionally, solar PV can avoid transmission network losses. We assume that solar PV generation avoids the 1.5%

average transmission system losses and not the higher losses that the system incurs during peak periods.[168–170]

Thus, Equation 4.7 defines the total short-run electricity system costs that distributed solar PV avoids. Based on our review of generator marginal cost data, we assume distributed solar PV avoids 50 €/MWh of electricity generation costs in the base case at grows with inflation (2%). We vary this from 20-80 €/MWh in the sensitivity analysis. Including transmission and distribution losses, distributed solar PV avoids 56 (22-90) €/MWh in electricity system costs. We assume that our low avoided generation cost estimate captures potential increases in generator costs due to solar PV generation. Such costs could include increased grid balancing requirements (e.g. generator ramping), which Leuken et al. (2012) estimates to be around 8-11 \$/MWh (7-10 €/MWh).[171]

$$PV\left(cost_{grid}\right) = \sum\nolimits_{n=1}^{N}\left(\sum\nolimits_{h}^{8760} g_h c_{gen,h} \times (1 + l_{tran})(1 + l_{dist})\right)\left(\frac{1}{(1+d)^n}\right) \tag{4.7}$$

Research also suggest that if solar PV generation coincides with system (or local area) peak demand, then distributed solar PV can defer or avoid infrastructure investments (i.e. medium- and long-run costs).[135,167,172] However, Table 4.5 shows that peak demand in Portugal occurs on winter evenings, after the sun has set. This is not surprising, as plug-in electric heat is still prevalent, and the adoption of air conditioning systems is still low in Portugal. Therefore we assume that solar PV will not avoid peak-capacity related generation, transmission, and distribution investments in Portugal.

Table 4.5. The timing and magnitude of Portuguese peak electricity demand. Data are from [108,121,173].

Year	Date and time	Peak

	(mm/dd/yyyy hh:mm)	(MW)
2005	1/27/2005 19:30	8,528
2006	1/30/2006 19:30	8,804
2007	12/18/2007 18:45	9,110
2008	12/2/2008 19:30	8,973
2009	1/12/2009 19:45	9,218
2010	1/11/2010 19:15	9,403
2011	1/24/2011 19:45	9,192
2012	2/13/2012 20:00	8,554
2013	12/9/2013 19:45	8,322

4.4 Results

Present cost of purchasing, installing, and operating a solar PV array

Using Equation 4.4 from the Methods, we calculate the present cost of purchasing a distributed solar PV array. We see that the capital costs of the system and the 23% value added tax are the primary costs; at a 5% real interest rate, loan interest is smaller than other costs. Total present costs per watt decrease as the array size increases, from 3.9 €/W for the 200W system to 2.0 €/W for the 1,500W system. The present cost of the 1,500 W solar PV system is lower than installed costs in 2012 in Germany.[174]

Table 4.6. Solar PV array price, tax, and interest.

Array	**Capital**	**Tax**	**Loan interest**	**PV(cost$_{solar}$)**
200W	*€ 600*	*€ 138*	*€ 51*	**€ 789**
500W	*€ 1,100*	*€ 253*	*€ 95*	**€ 1,458**
1,000W	*€ 1,750*	*€ 403*	*€ 151*	**€ 2,304**
1,500W	*€ 2,300*	*€ 529*	*€ 200*	**€ 3,029**

Present value of grid electricity purchases that a solar array owner avoids

We calculate that each kilowatt of solar PV capacity (kW_{DC}) will generate 1,540 kWh_{AC} in its first year of operation, which is a 17.6% capacity factor. Our estimate of PV generation is 40 kWh (2.6%) higher than a European Commission base case estimate of solar output for Lisbon, Portugal.[175,176] We find that the average Portuguese residential consumer (annual demand of 2,487 kWh) will self-consume the majority of solar generation from solar PV arrays smaller than 1,000 W. The average consumer can offset about 12% of their electricity demand using a 200 W PV array or 28% of their electricity demand using a 500 W PV array (Table 4.7). However, the average residential consumer in Portugal uses more electricity during evening periods and winter months than during daytime periods and summer months. Due to the low coincidence between consumer demand and solar generation, the marginal benefit (i.e. reduction in consumer demand) of increasing the size of the solar PV array diminishes rapidly. For example, a 1,000 W PV array only offsets 28% more consumer demand than a 500 W array, despite the 100% increase in array size.

Table 4.7. Our estimates of how residential panel owners will use the output from their solar PV array, based on our analysis of the coincidence of residential electricity demand and solar array generation.

System	Generation			Utilization	Cap. Factor
	Offset demand (kWh/y)	Resell (kWh/y)	Total (kWh/y)		
200 W	308	0	308	100%	17.6%
500 W	731	39	770	95%	
1000 W	982	558	1,540	64%	
1500 W	1,069	1,241	2,310	46%	

Table 4.8 shows the monetary value of the solar PV generation, which we calculate using our base case model parameters. A 500 W solar array can provide the panel owner 2,200 € (present value) in bill savings and resale revenue. This is approximately 0.20 €/kWh, or the

average retail tariff, plus tax, during periods that the solar array generates electricity. It is important to note that the average retail tariff that residential consumers avoid includes a variety of costs, such as the cost of generating electricity, the cost of delivering electricity, the cost of operating the grid, and the cost of energy policies. Some of these costs are fixed, i.e. cannot be reduced in the short run, while others are variable and decrease as residential consumer demand decreases. In order to calculate the value of distributed solar PV to the electricity system, we quantify the grid costs that distributed solar PV can avoid.

Table 4.8. The present value of grid electricity purchases that the solar array owner avoids. Savings include offset demand and revenue from reselling excess generation. All model parameters are from the "base case" scenario.

System	**Avoided bill**	**Avoided tax**	**Resale revenue**	**PV($price_{grid}$)** (incl. resale)	**PV($price_{grid}$)** (excl. resale)
200 W	*€ 755*	*€ 173*	*€ -*	**€ 928**	**€ 928**
500 W	*€ 1,786*	*€ 411*	*€ 20*	**€ 2,216**	**€ 2,196**
1000 W	*€ 2,340*	*€ 538*	*€ 290*	**€ 3,168**	**€ 2,878**
1500 W	*€ 2,525*	*€ 581*	*€ 642*	**€ 3,748**	**€ 3,106**

Present value of avoiding generating and delivering electricity to the panel owner

We calculate the present value of the cost of generating and delivering additional (i.e. marginal) electricity using Equation 4.7 from the Methods. Solar array generation is likely to displace grid generation, which costs around 50 €/MWh in year one, plus the losses associated with delivering the unit of electricity to the consumer, which are around 6 €/MWh. The remainder of the difference between the average residential retail tariff, 204 €/MWh, and the marginal cost of grid electricity are the sunk costs of the Portuguese electricity system. For example, the Portuguese regulator projects that 'Special Regime' generators will collect 1.7 billion Euro in subsidies, a quantity that is completely independent of consumer demand. In fact, if electricity demand decreases, then Portuguese regulators simply increase the fee (per kWh of consumption) to ensure these generators receive their full revenue guarantee.[122] Payments for previous (or planned) transmission and distribution system investments are also independent of demand. The gap between the panel owner benefit of solar PV generation, 204 €/MWh, and the value of solar PV to the grid, 56 €/MWh, equals the quantity of revenue that the Portuguese regulator needs to recover via increased electricity tariffs.

Table 4.9. A summary of the present value of the cost of the solar array, the present value of the cost of generating and delivering off-peak electricity, and the present value of the grid electricity purchases that the solar array avoid (with and without excess generation resale).

System	**PV($cost_{solar}$)**	**PV($cost_{grid}$)**	**PV($price_{grid}$)** (incl. resale)	**PV($price_{grid}$)** (excl. resale)
200 W	€ 789	€ 261	€ 928	€ 928
500 W	€ 1,458	€ 646	€ 2,216	€ 2,196
1,000 W	€ 2,304	€ 1,217	€ 3,168	€ 2,878
1,500 W	€ 3,029	€ 1,761	€ 3,748	€ 3,106

Panel owner benefits and costs

We find that the cost of distributed solar PV arrays smaller than 500W provide Portuguese consumers an economical alternative to grid electricity purchases. For example, a 500 W distributed solar array has a 700 € net present value for the average Portuguese consumer (Figure 4.2). Thus, even without additional policy support such as up-front purchase subsidies or incentives, tax breaks, feed-in-tariffs, and without 100% net-metering at the consumer's retail rate, Portuguese consumers have an economic incentive to install a distributed solar PV array. Small solar PV arrays are net present value positive across the range of array sizes we evaluate both with and without excess generation resale. Also of note is that electricity bill and tax savings in each year are greater than loan payments, indicating solar immediately saves panel owners money.

When the panel owner resells excess generation, the net present value of 1,000W and 1,500W solar arrays is similar to the 500W array. However, when panel owners do not resell excess electricity generation (and thus avoid the additional metering infrastructure, permitting, and inspection requirements) the 1,000W and 1,500W solar arrays provide a smaller net present value than the 500 W array due to the larger fraction of solar generation the panel owner spills.

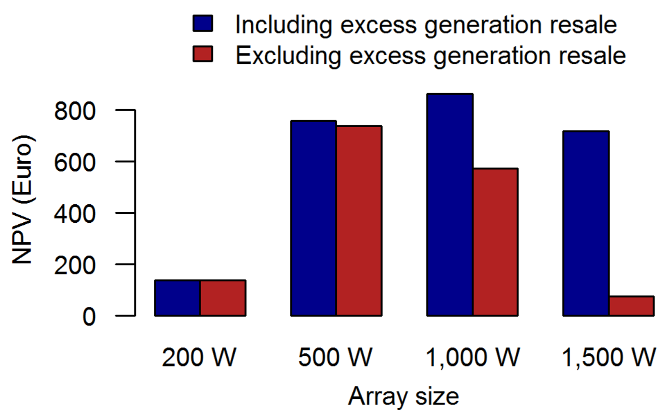

Figure 4.2. The panel owner's net present value for several distributed solar PV array sizes. A grid connected system can resell electricity generation in excess of panel owner demand to the grid. A stand-alone system spills electricity generation in excess of panel owner demand. A grid connection requires an initial inspection, certification fee, metering, and periodic inspections. A stand-alone system up to 1,500 W only requires the panel owner to notify the utility of the presence of the array.

Figure 4.3a breaks the present value of panel owner benefits and costs into their individual elements. We observe that panel owner bills savings are a combination of avoiding electricity system costs (i.e. the savings of not generating and delivering additional electricity), avoiding paying grid sunk costs, and the tax on both. The largest category of bill savings is the sunk grid costs that panel owners avoid paying.

On the other hand, while we find that distributed solar PV is likely to have a positive NPV for the average low-voltage electricity consumer, we do not expect the total capacity of distributed solar PV to grow rapidly. The majority housing units in the major population centers of Portugal are multi-family housing units.[177] Thus many families will not have the opportunity to install a distributed solar PV array.

Overall ratepayer and non-panel owner benefits and costs

Distributed solar PV contributes electricity to the electricity grid but requires an investment in install. If the cost of the electricity that solar PV provides is lower than the cost of alternate methods of meeting the same demand, then distributed solar PV will decrease electricity grid costs overall. No matter who collects these benefits, consumers on average would be better off due to solar PV. Conversely, if distributed solar PV was more costly than another method of meeting electricity demand, then consumers on average might be worse off due to solar PV. Overall benefits are proportional to the difference between the cost of distributed solar PV and the cost of alternate methods of meeting electricity demand.

Distributed solar PV also contributes to shifting resources among electricity consumers. This occurs because of the average cost pricing structure that is present in most electricity grids (I discuss average cost pricing in the footnote below). “Cost shifting” is proportional to the difference between how distributed solar PV changes the panel owners cost of meeting electricity demand and the cost of alternate methods of meeting electricity. For example, if distributed solar PV enables an existing power plant to avoid generating an additional unit of electricity, grid costs are likely to decrease by less than panel owner’s costs. This is because the consumer will benefit. In this scenario, the panel owner is shifting fixed grid costs from the panel owner’s electricity bill onto other consumers’ electricity bills.

In summary, distributed solar PV is not a zero sum game from the perspective that distributed solar PV is likely to increase total grid costs and make consumers overall worse off. Our results suggest that distributed solar PV is not yet cost effective for the Portuguese electricity system: the cost of distributed solar generation remains greater than the cost of using the grid to generate and deliver an additional unit of electricity. Total electricity system costs increase by between 900 – 2600 €/kW_{DC} of distributed solar array capacity, depending on array size. However, distributed solar PV also redistributes the cost of the electricity system by generally shifting costs from panel owners onto non-panel owners. We estimate these overall grid and consumer impacts based on the following results.

Figure 4.3b shows that the avoided grid generation and delivery costs of solar generation are smaller than the cost of the solar generation. Our results suggest that the 500 W solar array avoids about 600 € in grid generating and delivery costs over 15 years. Thus, in order for solar PV to reduce the cost of meeting consumer electricity demand, the present price of the 500 W solar array would need to be less than 600 € installed, or less than 1.2 €/W_{DC} installed. That solar PV is only cost effective at such a low price per Watt of installed solar PV reflects the low cost of using the grid to generate and deliver electricity during off-peak periods (~60 €/MWh), which is when solar arrays generate electricity in Portugal.

Figure 4.3c shows that for each Portuguese consumer that adopts a 500 W solar array, other Portuguese consumers will pay an additional 1,600 € in electricity bills. As we discuss above, this is approximately equal to a wealth transfer from non-panel owners to panel owners of 0.14 €/kWh. This wealth transfer is higher than the subsidies that consumers pay to other generators, for example: the average special regime generator (0.08 €/kWh), CAE generators (0.04 €/kWh), and CMEC generators (0.02 €/kWh). On the other hand, the current solar PV wealth transfer is smaller than the average subsidy that consumers provide to existing solar PV installations and "micro-generators" (many of which are solar).[122]

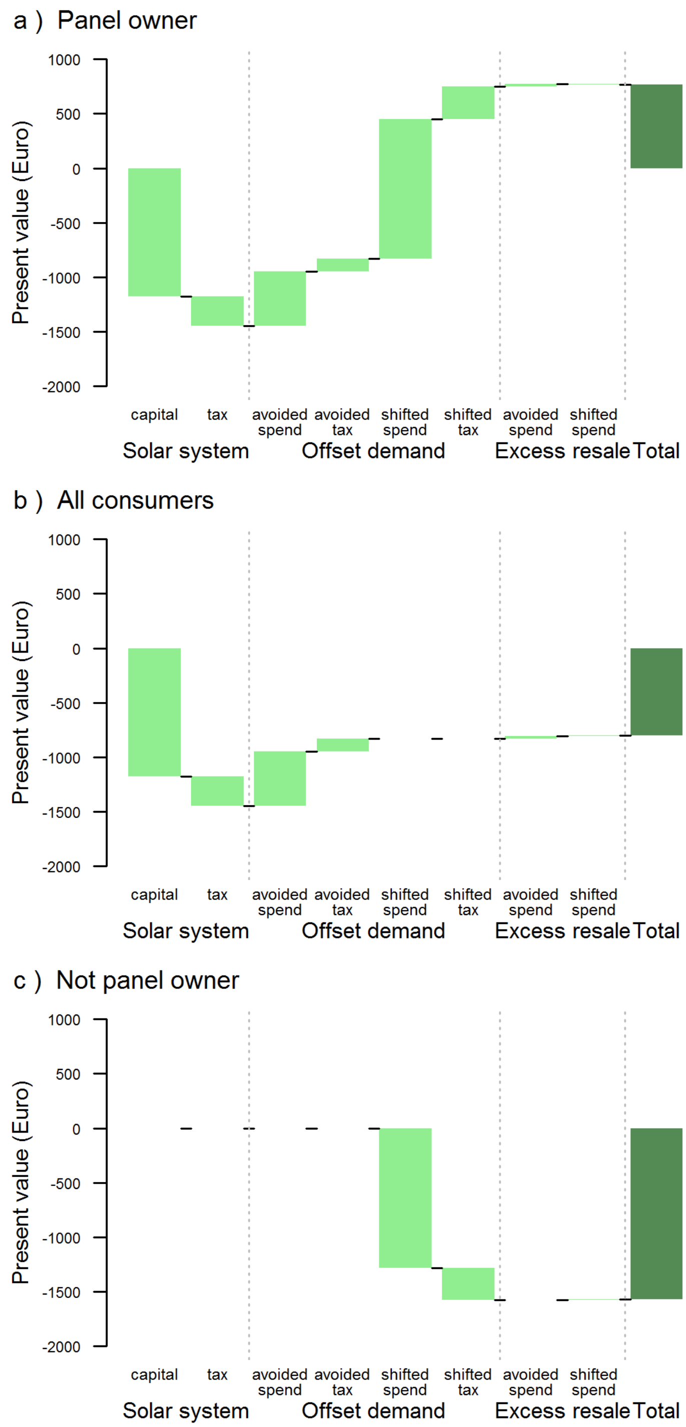

Figure 4.3. The present value of a 500 W solar array from the perspective of the a) panel owner, b) all ratepayers, and c) non panel owners. We show each component of the present value. Solar System refers to the purchase price of the solar system, including the capital, tax, and interest payments. Offset Demand refers to changes in expenditures that occur when the panel owner uses the solar generation to directly offset household demand. Excess resale refers to changes in expenditures that occur when the panel owner resells solar generation to the grid.

4.5 Sensitivity analysis

Our base case scenario relies on multiple parameters that are either uncertain or may evolve in the future. Therefore, we vary several technical and economic parameters and re-calculate the cost effectiveness of solar PV from the panel owner, non-panel owner, and overall ratepayer perspectives. Specifically, we vary:

- The solar array price since prices decreased rapidly over the past decade;
- The lifetime of the solar array to represent either the technical lifetime of the array or the panel owner's investment horizon;
- The marginal cost of electricity in Portugal since the market and energy policies make identifying the exact marginal generator and price infeasible;
- The rate of electricity price growth since this value is uncertain due to economic conditions, policy choices and the Portuguese tariff deficit;
- The interest rate on the loan that the consumer uses to finance the solar array since interest rates will vary across consumers and market conditions;
- The discount rate applied to future benefits since this is a subjective parameter;
- The variability of residential demand since the ERSE average load profiles to not represent the actual variability of residential demand.

For all variables, we change one parameter from the base case value to the sensitivity case value and re-calculate the net present value of solar from all perspectives. Table 4.10 shows the values of each variable in each sensitivity case. With respect to the variability of residential electricity demand, research shows that consumer demand exhibits substantial variability across many time scales.[150] To add variability to the average residential demand in each hour, we assume demand in each hour is log-normally with mean demand equal to the ERSE mean demand in that hour. We define the standard deviation such that consumer demand during peak periods does not exceed their contracted power (most commonly 6.9kW) more than several times each year. Thus we introduce variability in consumer demand without changing total annual consumer demand and while limiting hourly consumption to the consumer's contracted power.

Table 4.10. The model parameters we vary in the sensitivity analysis. Note, "Low NPV" and "High NPV" refer to the effect of the change in the parameter value from the perspective of the panel owner. We perform the sensitivity analysis on the benefits and costs of the 500 W solar array.

Parameter	Low NPV	Base case	High NPV	Notes
Solar array price (capital + tax + interest)	1,823	1,458	1,094	(Euro) ± 25% of base case
Solar array lifetime	10	15	20	(Years)
Electricity tariff growth	1%	2%	3%	(Annual) Based on historic changes
Loan interest rate	7%	5%	3%	(Annual)
Discount rate	7%	5%	3%	(Annual)
Marginal cost of electricity	0.022	0.056	0.089	(€/kWh)
Res. demand variability	Yes	No	No	Draw from log-normal dist.

Figure 4.4a shows the panel owner's net present value is most sensitive to the solar array lifetime/investment horizon, the purchase price of the solar array, and the variability of the consumer's demand. The NPV of the 500 W array decreases substantially, but remains positive when we decrease any of these individual paramters. Consumers should be aware that since residential demand for electrictiy is sporadic, especially during daytime hours when the solar array generates electricity, the NPV of the solar array is likely to be lower than our base case estimate. Assuming residential load exhibits log-normal variability as we model, the actual NPV of a 500 W solar array is 200 €. Given the relative importance of this parameter, we recommend that consumers investigate their household load profiles before investing in solar PV.

Alternatively, policymakers could help educate consumers that household demand must coincide with solar generation in order to get the most value from the solar array. Unexpectedly, changing real electricity price growth from 1% to 3% has a smaller impact than other factors, including the loan rate.

Figure 4.4b shows that the 500 W solar array is net present value negative to non-panel owners for all scenarios that we test. The NPV of solar panels to non-panel owners remains at -400 € even when the maringal price of electicity in Portugal – and thus the marginal benefit of solar generaation – is 90 €/MWh. Additionally, several parameters whose changes correspond to an increase in the panel owner NPV actually decrease the non-panel owner NPV. For example, increasing the array lifetime/investment horizon allows the panel owner to increase their net present value. Since the majority of the panel owner benefit is avoiding paying for sunk grid costs, this simply increases the amount that non-panel owners pay over the lifetime of the solar array.

Figure 4.4c shows that the 500 W solar array is net present value negative to all consumers for all scenarios that we test. Of the parameters we test, the array price and the marginal price of electicity in Portugal have the largest effect on the overall NPV of the solar array. However, while a high marginal price of electricity in Portugal would result in a less negaive overall NPV, the marignal price of electiricty does not affect the NPV of the solar array for panel owners. The results of the sensitivty analysis further support our conclusion that shifting sunk costs onto non-panel owners is the primary benefit of solar PV for panel owners. This conclusion is robust to changes in the price of panels and changes in other electricity system and economic parameters.

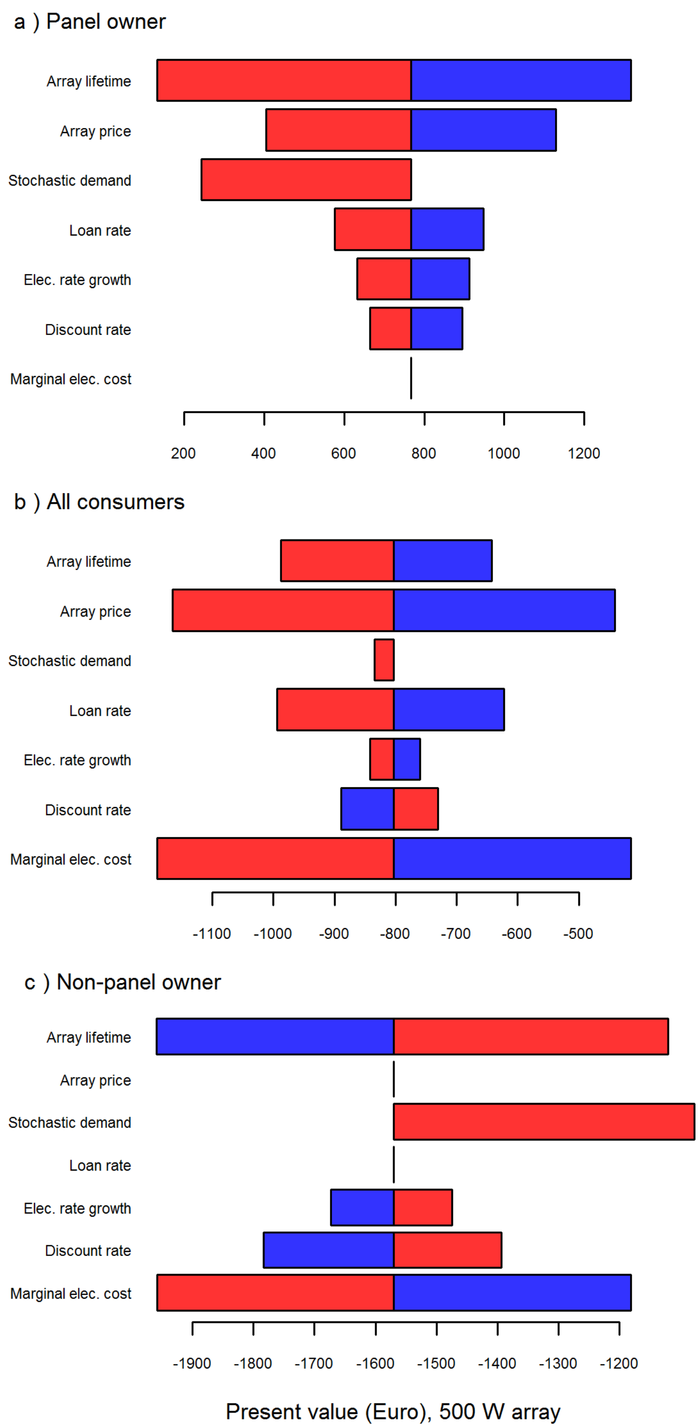

Figure 4.4. The results of our sensitivity analysis for a) panel owners, b) non-panel owners, and c) consumers overall. The red bars show the NPV of the 500 W solar array under the "Low NPV" conditions and the blue bars show the "High NPV" conditions. As we note in the table above, the "Low NPV" and "High NPV" conditions refer to the effect of the change of the parameter value from the perspective of the panel owner. We show the parameters in the same order for all three perspectives. This order corresponds to most important (on top) to least important (on bottom) from the perspective of the panel owner. Note the difference x-axis scales between the perspectives.

4.6 Discussion and Policy Recommendations

Portugal's new distributed generation net metering policy comes at a time when multiple nations are trying to appropriately value distributed solar PV. In dramatically decreasing the feed-in-tariff and switching to a net-metering policy, Portugal reduced the potential for excessively compensating panel owners if the price of solar PV falls faster than the feed-in-tariff. This was a problem for Germany when the combination of high feed-in-tariffs and rapidly falling solar PV costs caused very high rates of solar PV adoption. Further, the current net-metering policy of compensating panel owners at 90% of the wholesale market rate for excess generation is less generous than in other places, such as California. In California, the system pays panel owner the retail rate for excess generation, and not the wholesale market rate. In fact, the Portuguese solar PV policy framework is relatively conservative overall: there are currently no installation incentives, tax breaks, guaranteed revenue, and the system does not purchase excess generation at the retail rate. Thus, our conclusion that solar PV is net present value negative for the Portuguese electricity system and that consumers subsidize solar PV at a higher rate than some other preferentially treated generators warrants further inspection.

Since the EU states that renewable policies are designed to transition away from a fossil energy system that generates carbon dioxide emissions, we estimate the value of the carbon dioxide emissions that solar generation will avoid. The 500 W solar array will generate about 12 MWh of electricity over 15 years; total Portuguese electricity system costs will increase by 1,300 € (present value). We assume this generation displaces natural gas or coal based centralized generation with emission factors of 0.5 and 1.0 metric tons per MWh, respectively. Thus carbon dioxide emissions would need to be valued at between 100 and 200 €/metric ton in order for the avoided carbon dioxide emissions to justify the increase in system expenditures. This is substantially higher than the current EU emissions trading system carbon dioxide permit price (which is already reflected in generator bids) and higher than most estimates of the "social cost" of carbon dioxide emissions.

Another potential justification of the increase in system costs is that solar generation may avoid the emission of other pollutants that damage human and environmental health. The Portuguese specifics of this claim deserve further study. However, a Europe-wide research indicates that urban emissions and urban transportation emissions are a much greater concern than electricity generator emissions.[178]

The Portuguese government has several options to manage the potential issues of solar PV a) causing a less cost effective electricity system and b) leading to a wealth transfer from non-panel owners to panel owners. First, Portugal could institute a solar PV fee that helps to offset the shift in expenditures from panel owners to non-panel owners. Given that solar PV is net present value positive for panel owners due to the shift in expenditures from panel owners to non-panel owners, this option would likely eliminate the private incentive to adopt solar PV. The benefit of this option is that non-panel owners do not subsidize solar array ownership. Second, Portugal could overhaul the current tariff system and institute some form of "real time" or marginal pricing scheme. Some economists believe that this will help improve the efficiency of the electricity system. However, it is unclear how the Portuguese electricity system will recover its large sunk costs under this scenario. Further, as with instituting a fee on solar, if the Portuguese electricity system charges consumers the marginal price of electricity then panel owners will receive much smaller benefits from installing solar PV. Based on our estimate of the marginal price of electricity in Portugal, solar PV would be net present value negative for individual in this scenario. Finally, the Portuguese government could take no action at present.

This preserves the potential shift in expenditures from panel owner to non-panel owner but maintains the private incentive for solar adoption. We recommend the Portuguese government consider reducing the burden that solar PV places on non-panel owners, but recognize that the current distributed generation net metering policy fits within broader environmental, energy, and social goals.

4.6.1 Pairing distributed solar PV with storage

One recent development that may increase the value of renewable energy resources is to combine renewable energy systems with electricity storage. We discuss the value of storage from two perspectives: the "grid scale" perspective, as if the storage facility were paired with a large renewable energy resource and the private perspective if private consumers are allow to pair distributed solar PV with storage.

From the grid perspective, electricity storage can allow the intermittent output of renewable energy resources to be stored at the time of generation for use at a more beneficial time. For example, if electricity prices are low when the sun shines, then the owner of a storage device has the option to store generation and resell the electricity in higher prices hours. However, storage does not need to be paired with renewable resources to price intertemporal price arbitrage, and in fact, pairing storage with renewables limits the opportunity for intertemporal electricity price arbitrage. This is because a stand-alone storage system can charge (i.e. buy) during the cheapest periods of the entire year and discharge (i.e. resell) electricity during the highest value hours of the entire year. The storage component of a renewable-storage system is limited to charging when the renewable resource is operating and can discharge during the highest value hours of the entire year[4]. Thus the renewable-storage combination *could at best* produce the same profit as a stand-alone renewable resource and stand-alone storage facility, and only if the renewable resource is producing electricity during all of the cheapest periods of the year. In summary, from a grid perspective, storage and renewables do not need to be modeled as a combination resource in order to determine the benefits or costs of either. Modeling the combination resource actually places a potential constraint on the combined profits of the facilities.

We are confident that pairing storage with distributed solar PV will not increase the benefit of solar PV beyond what could be achieved by simply installing an independent storage facility. Further, we cite the cancellation of several pumped hydro power plants in Portugal as evidence that current economic and grid conditions may preclude even the most widely adopted source of electricity storage, pumped hydro, from being a net-benefit to the electricity grid.

On the other hand, storage could change the private benefits of distributed solar PV. When a private consumer owns solar panels, the value of an additional unit of solar generation varies depending on whether the consumer offsets their own demand or resells the generation to the grid. As we discuss in the Methods and Results above, offsetting personal demand has an average value of 204€/MWh, while reselling the electricity has an average value around 30€/MWh. Thus if storage can allow the private consumer to storage solar generation during periods that generation exceeds personal demand, then storage can allow the private consumer to "trade" 30 €/MWh electricity resales for 204 €/MWh reductions in personal demand. However,

[4] One cannot make the argument that charging the storage resource with renewable energy costs 0$/MWh, versus an independent storage facility that pays the prevailing grid electricity rate. When the renewable-storage system uses renewable output to charge the storage device, the renewable resource forgoes revenue which equals the market price the renewable resource would have received for that generation. Thus the opportunity cost of charging the storage device is the market price, exactly equal to the price that an independent storage owner pays to charge the storage device.

our research estimates that when private individuals use solar PV to reduce personal demand costs for other consumers increase by approximately 140 €/MWh. Therefore, under the current policy, allowing private individuals to pair distributed solar PV with storage is likely to further increase the subsidy that panel owners receive from non-panel owners and further increase overall grid costs.

4.7 Conclusions

In 2008, the European Parliament adopted the European Commission's (EC) "20-20-20" goals in order to address global climate change concerns and to tap the potential economic and energy security benefits of energy systems based on renewable energy resources. Under the 20-20-20 package, Portugal needs to produce 60% of total electricity using renewable energy sources (or RES) by 2020. However, the total cost of subsidy policies that lead this transition now account for approximately 33% of residential consumers electricity bills. In light of both the 20-20-20 climate goals and the increasing need to achieve these goals in a cost effective manner, we quantifying the benefits and costs of distributed solar PV in Portugal for panel owners, ratepayers as a whole, and the specific group of ratepayers that does not own solar panels. We measure the benefits and costs of distributed solar PV from these perspectives using the present value of the cost of a distributed solar PV array, the present value of grid electricity purchases that solar panel owners avoid, and the present value of grid generation and delivery costs that the grid avoids when panel owners consume less electricity. We find that solar PV is net present value positive for the average Portuguese electricity ratepayer that owns a solar array. The most attractive option for an average consumer is a 500W array, with a net present value of 700-800€ relative to a present cost of about 1100€. On the other hand, the cost of distributed solar PV is higher than the cost of producing and delivering electricity during periods that solar PV arrays generate electricity, including marginal infrastructure costs such as transmission and distribution line needs. Thus, ratepayers as a whole pay 900-2600€ more in total costs for each kilowatt of distributed solar PV capacity that panel owners install; the 500 W solar array increases total system costs by 1600€. Further, panel owners also avoid paying sunk grid costs, such as revenue guarantees to other renewable generators and the costs of grid infrastructure, which will lead to retail prices increases for all consumers. As a result, non-panel owners (as a whole) will pay an additional 1600€ in bills for each 500W array that panel owners install. This is equivalent to a 140€/MWh subsidy to panel owners, which is larger than the subsidy that many other Portuguese generators receive but smaller than the subsidy for existing solar PV arrays. Portuguese policy-makers could reduce this subsidy by instituting some type of solar PV fee (relatively simpler) or changing the rate structure such that retail prices more closely reflect underlying costs (more complex). Alternatively, Portuguese policy makers could maintain the existing policy. The subsidy per unit of installed solar PV will not change; however, the large number of consumers that live in multi-family housing (and may not be able to install solar PV) suggests that the total value of the subsidy from panel owners to non-panel owners will remain limited.

5 Conclusions and Policy Recommendations

Humans and human systems depend on energy as a key input for nearly all activities. The ubiquitous consumption of energy is a hallmark of developed societies and is correlated with gross domestic product. The benefits of energy consumption are hard to understate. From simple tasks such as reading after dark to delivering goods, food, and information quickly over long distances, energy consumption is an enabler and multiplier of human efforts.

The "revealed preference" for increasing energy consumption, regardless of the internal and external costs of the required energy extraction, conversion, and delivery infrastructure was a 20th century hallmark in the United States and western Europe. Governments either sponsored, or actually executed, the damming of major rivers, exploitation of vast fossil reserves, construction of power plants without pollution controls, and generally encouraged the growth of energy supplies and demand. While energy demand growth has slowed down recently, the United States and Western Europe continue to consume vast quantities of energy.

Recently, however, citizens in the United State and Europe, among a small set of other nations, began to place a higher value on the costs of energy consumption, including social costs such as the human and environmental damages caused by energy-related pollution. In fact, citizens are demanding cleaner, less polluting energy resources but which are not less plentiful or more costly. As a result, policymakers are attempting to balance the benefits of reducing energy related pollution with the costs, or perceived costs, of these interventions.

In this Dissertation, I assist citizens and policymakers to identify the benefits and costs of interventions that reduce or displace consumer energy demand. I focus specifically on demand side interventions because of the strong citizen and policymaker demand for energy solutions that result in low to no pollution and social costs. Demand-side interventions, such as reducing energy demand through energy efficiency measures or decreasing net energy demand by installing distributed renewable energy resources, are an area of citizen and policymaker interest because such demand side solutions can offer many of the same cost and quality characteristics of supply side interventions but do not increase pollutant emissions.

In Chapter 2 I quantify the avoided pollutant emissions, and monetary value of those emissions savings, when buildings reduce their energy demand by installing cost-effective energy efficiency measures. I find that, on a national basis, the "social" benefits of improved energy efficiency make up approximately 20% of the total (i.e. private plus social) benefits of commercial building energy efficiency. Further, the government does not currently estimate these social benefits or use such estimates to determine the incentives that building owners receive for improving their energy efficiency. We conclude that the social benefits of building energy efficiency measures are an important component of the total benefits of building energy efficiency and are not fully valued when determining government decisions regarding efficiency investments. We recommend that the U.S. federal government take steps to quantify and incorporate the social benefits of efficiency measures into efficiency investment decisions, such as the monetary incentives that building owners receive for improving their building energy efficiency.

In Chapters 3 and 4 I examine how demand side interventions affect the larger energy systems that they are embedded in. I help expand the literature that examines both the energy system costs and benefits of demand side interventions. For both commercial building energy efficiency measures in the northeastern United States (Chapter 3) and distributed residential solar PV in Portugal (Chapter 4), I quantify how demand side interventions change the economics of existing energy systems. These studies utilize on benefit-cost analysis and integrated resource planning principles. Both Chapters show that demand side resources can provide benefits to the energy system, and thus consumers, but that existing energy tariffs do not appropriately incentivize demand side interventions. In Chapter 3, we identify instances where existing energy tariffs both under-compensate and over-compensate demand side resources relative to the value of those resources. Our results indicate that policymakers should recognize the difference between fixed and variable system costs. Ideally, the variable energy tariff should reflect the variable cost of providing that energy. Traditional cost-of-service (i.e. average cost) based rates do not reflect the varying marginal costs of energy and can over-incentivize demand side interventions which marginal costs are low relative to average costs and under-incentivize demand side interventions when marginal costs are high relative to average costs.

At a high level, this Dissertation shows that research has not yet quantified the full benefits and costs of demand-side options for addressing our energy challenges. Additional research could help fulfill this need. Over the long term, research should identify the full marginal benefits and costs of demand side interventions in an integrated manner. An integrated approach has the potential to provide citizens and policymakers with a 'one-stop-shop' for demand side solutions to energy challenges. This future research should also recognize and incorporate the time and location dependent effects that this Dissertation identifies as important determinants of the total value of demand side interventions. In the short term, research should continue to explore the economic and environmental effects of demand side interventions over a wide range of energy systems, policies, timescales, and locations. My existing research identified the importance of these details when calculating the overall value proposition of demand side interventions but did not identify a general set of such conditions that are likely to affect he value proposition of demand side interventions. This research would be especially valuable to help policymaker ensure they are selecting an appropriate demand side intervention given the challenge presented and local energy system characteristics.

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Appendices

7 Chapter 2 Supplemental Information

7.1 Differences between ASHRAE 90.1-2007 and 90.1-2010

Thornton (2011)[1] discusses 90.1-2007 and 90.1-2010 commercial building energy codes:[7] over 100 changes occurred between the two code levels. Only 41 are expected to affect building energy consumption. Table 7.1 shows these changes, and identifies the buildings affected. Of all the individual changes, several categories of changes have the largest effect on building energy savings. First, heating and cooling energy intensities decrease by 50% and 30% respectively. Reductions in air leakage (i.e. increases in building air tightness) drive these energy savings, as the minimum efficiency of heating and cooling equipment and insulation standards did not change appreciably. Next, changes in maximum lighting power density reduced interior and exterior lighting energy demands by 21% and 52% respectively. Finally, variable speed fans and improved fan efficiency decreased fan energy consumption by 31%. Plug loads, pumps, hot water heaters, and other sources of energy demand contributed substantially smaller savings to the overall building energy savings estimates.

Table 7.1. Overview of the 41 building energy code changes for commercial buildings. Adapted from [7].

Building System Affected	**Description**	**Prototypes Affected**															
		Office	Office_	Office	Retail	Strip Mall	School	School	Healthcar	Hospital	Hotel_	Hotel	e	Fast Food	t	Apartmen	Apartmen
Envelope	Sets requirements for high-albedo roofs		X	X	X	X	X	X	X	X	X	X				X	X
Envelope	Updates the building envelope requirements for metal buildings												X				

Envelope	Removes the exception to vestibule requirements in Climate Zone 4	X												X	X		
Envelope	Revises air leakage criteria for windows and doors	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Envelope	Requires continuous air barrier and performance requirements for air leakage of opaque envelope	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Envelope	Limits poorly oriented fenestration; favors south facing fenestration over west-facing fenestration									X	X						
HVAC	Modifies requirements for energy recovery			X	X		X	X		X							
HVAC	Revises the airflow limits for which new energy may be used for reheating or re-cooling in DDC systems		X	X			X	X	X	X		X					
HVAC	Increases minimum chiller performance and adds a second Path B for alternative chiller efficiency requirements			X				X		X		X					
HVAC	Establishes requirements for single zone VAV fan modulation on cooling units				X	X	X	X						X	X		
HVAC	Requires open cooling towers with centrifugal fan units of 1,100 gpm			X						X							
HVAC	Prescribes maximum flow rates through chilled water and condenser water piping			X				X		X		X					X
HVAC	1. Removes the requirement for VFDs on variable flow heating water systems. Lowers VFD threshold. 2. Limits differential pressure set point and requires reset with DDC. 3. Adds water-cooled air conditioners to systems requiring isolation valves. 4. Adds VFD pumping requirement to hydronic heat pumps and water-cooled unitary AC			X				X		X		X					

HVAC	Removes exception for VAV turndown for zones with special pressurization requirements								X	X							
HVAC	Modifies the requirements for kitchen hood exhaust systems and make-up air systems						X	X		X		X		X	X		
HVAC	Requires supply air temperature to be reset for multi-zone HVAC systems		X	X			X	X	X	X		X					
HVAC	Improves PTAC and PTHP efficiency										X						
HVAC	Requires that single-zone VAV systems meet the fan power requirements for constant volume systems				X	X	X	X						X	X		
HVAC	Removes the exception for automatic damper requirements for buildings under 3 stories	X			X	X	X	X					X	X	X		
HVAC	Modifies pipe sizing table for 8" pipe			X				X		X		X					X
HVAC	Requires mulit-zone VAV systems to have controls that optimize ventilation		X	X					X	X		X					
HVAC	Updates economizer requirements	X	X	X	X	X	X	X	X	X	X	X	X	X	X		
HVAC	Limits pressure drop of energy recovery devices			X	X		X	X		X							
Power	Establishes step-down transformer efficiencies			X	X		X	X		X		X					X
Power	Requires noncritical receptacle loads to be turned off based on occupancy or scheduling	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Lighting	Requires automatic daylighting controls when skylights are present				X		X	X					X				
Lighting	Categories for external lighting allowances are expanded and LPDs are defined	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Lighting	Reduces the building size threshold where automatic lighting shutoff is required	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Lighting	Requires automatic shutoff control to be manual on except in certain spaces	X	X	X													
Lighting	Defines top lit and side lit daylight spaces over a certain size		X	X	X		X	X					X				
Lighting	Requires skylights in spaces >10,000 ft2				X			X					X				
Lighting	Removes bathrooms from the requirements for on/off controls located at the entry to hotel/motel guestrooms										X	X					
Lighting	Reduces additional lighting power allowance for retail display					X											
Lighting	Changes LPD allowances	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Lighting	1. Requires exterior lighting control rather than just control capability. 2. Adds bi-levels control. 3. Adds control of exterior lighting after midnight	X	X	X	X	X	X	X					X	X	X		
Lighting	Requires stairwell lighting to be automatically controlled	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X
Lighting	Requires daylight sensor control for sidelit spaces	X	X	X			X	X	X	X	X	X	X	X	X		
Lighting	Reduces the area threshold where skylights are required to be designed into building spaces						X						X				
Lighting	Reduces lighting power allowance for some lobbies	X	X	X	X		X	X	X	X	X						
Other Equip.	Updates motor efficiency tables	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Other Equip.	Adds requirements for elevator ventilation and lighting		X	X				X	X	X	X	X				X	X

Based on the research of Kneifel (2011) and Thornton et al. (2013), we estimate the simple payback period of a subset of these efficiency measures using a 6% discount rate. This subset includes efficiency improvements such as insulation upgrades and HVAC upgrades across multiple locations in the United States. We observe that most efficiency measures have payback periods of less than 10 years, which indicates the net present value of the efficiency measure is likely positive over reasonable estimates of the efficiency measure lifetime and thus the efficiency measure is cost-effective.

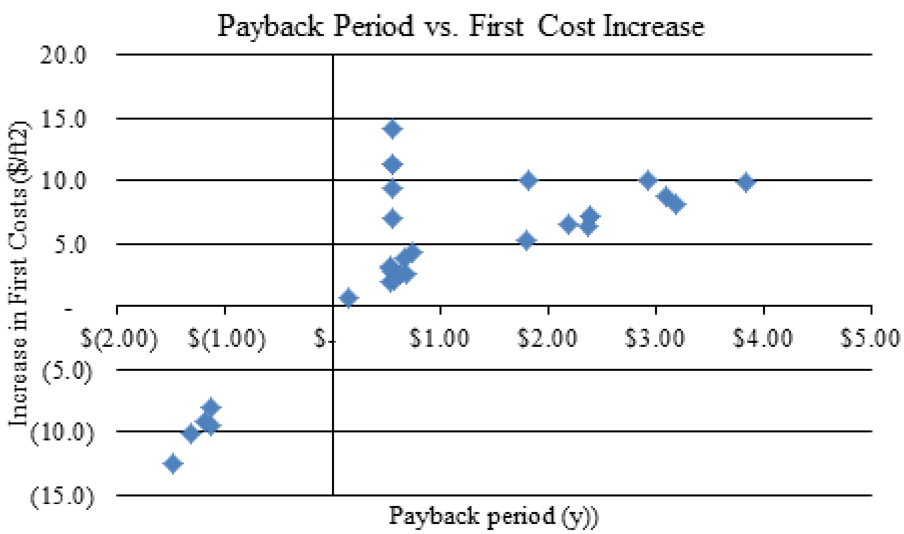


Figure 7.1 The simple payback period of a range of efficiency measures, based on research from Kneifel (2011) and Thornton et al. (2013)

7.2 Current Commercial Building Energy Code By State

The Building Energy Codes Program tracks the current commercial building energy code adopted by each state in the U.S. Currently, most states have adopted the 90.1-2007 version (28 states); 10 states have less stringent codes and 13 states have more stringent codes or a more stringent code that will take effect at a later date (Figure 7.2).

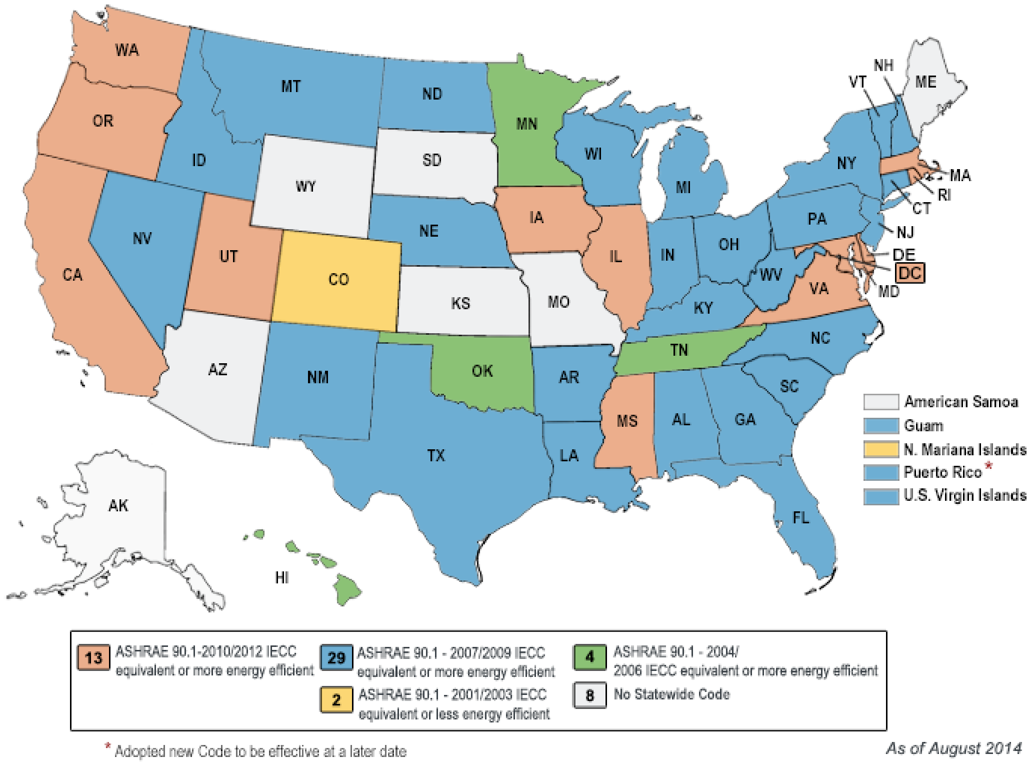


Figure 7.2. Current commercial building energy code adoption status, from [47]. Last accessed: October 30, 2014.

7.3 Energy Plus simulated energy savings by building Type and climate zone

Figure 7.3 shows that the 90.1-2010 building energy code results in heterogeneous savings across building types, climate zones, and fuel types. As expected, colder climates tend to have larger site natural gas savings than warmer climates due to the larger heating demands in colder climates. Likewise, warmer climates tend to have larger electricity savings than cool climates, due in part to the larger cooling load in warmer climates. Savings also vary dramatically between building types, ranging from zero (or even an increase in natural gas demand) to savings of over 500 MJ/m^2. A part of the difference in savings is explained by the baseline energy intensity of the building type. However, different building types continue to have substantial variability in energy savings, as measured by the percentage reduction in each type of energy consumption, indicating that some building types may contain larger amounts of cost-effective energy efficiency.

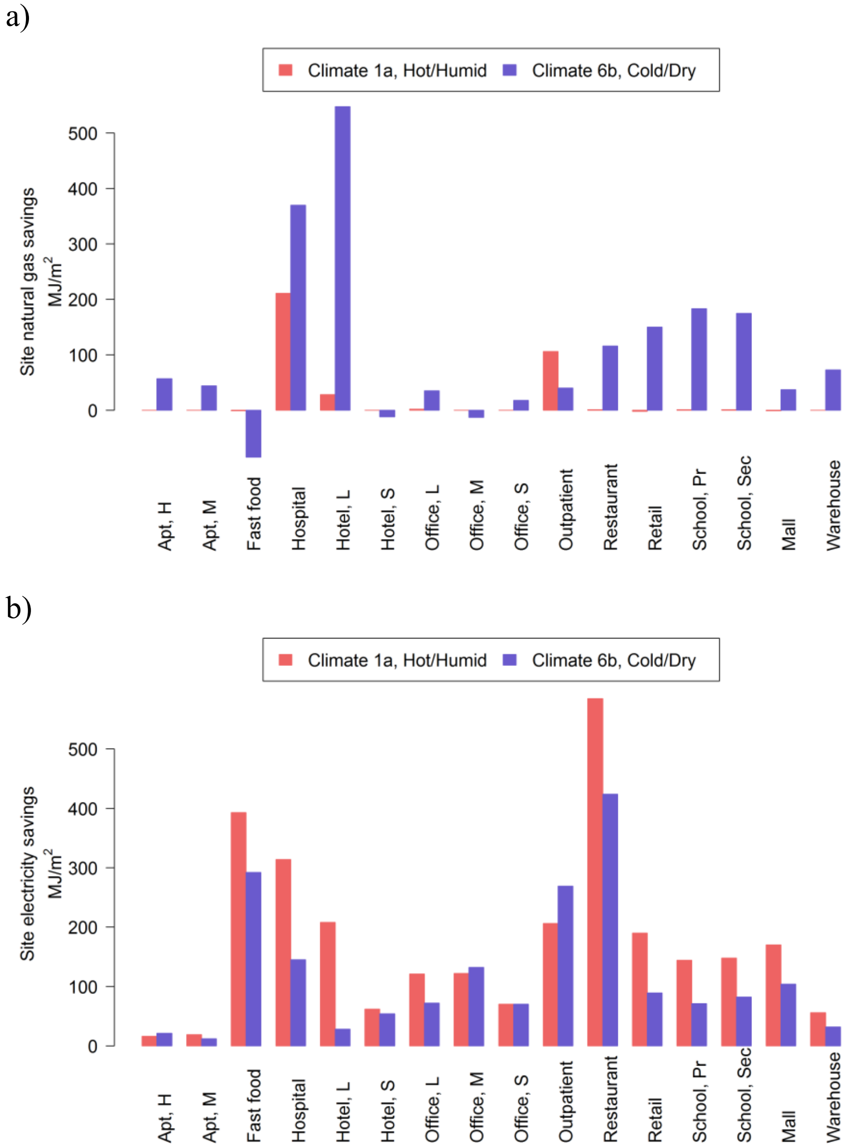


Figure 7.3. Natural gas savings (a) and electricity savings (b) in megajoules per square meter (MJ/m^2). Savings is shown for each of the 16 building types for 2 of the 14 U.S. climate zones.

7.4 Comparing Simulated and Actual Building Energy Consumption Data

We compare simulated electric and natural gas energy consumption for buildings at the ASHRAE 90.1-2004 code level with the distributions of building electric and natural gas energy consumption for buildings built between 1990 and 2003 from the 2003 CBECS survey.[22,23] We make this comparison for all building types, except the mid- and high-rise apartments due to the absence of CBECS data, to determine how the energy consumption of each individual building prototype compared with the actual commercial building stock. We compare EnergyPlus building prototypes with their most similar CBECS counterpart; for example, small, medium, and large offices are all compared with the CBECS "office" building type and both fast food and sit-down restaurants are compared with the CBECS "food service" building type. Figure 7.4and Figure 7.5 show the results of the comparison for electricity and natural gas, respectively. The simulated energy consumption of most building prototypes fell within the 95% confidence interval for the mean energy consumption of commercial buildings constructed since 1990.

We do not further sub-set the data, for example, by comparing building energy consumption by climate zone, because the CBECS dataset is limited by the relatively small number of buildings sampled which quickly results in very small sample sizes that may not be representative of the larger building population.

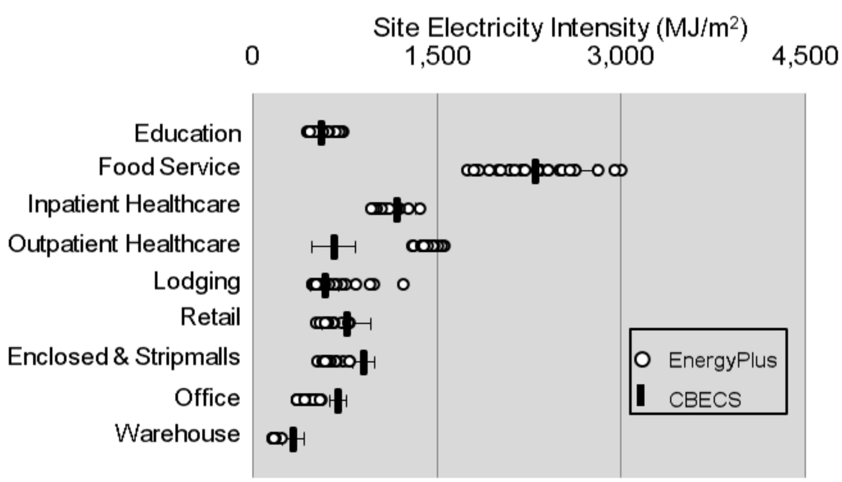


Figure 7.4. Site electricity intensity comparison between the simulated energy consumption of building prototypes and the CBECS calculated national distribution for buildings of the building type that have been constructed since 1990 (CBECS Table C22a). The EnergyPlus output for each building type was variable because each building was simulated across all 15 U.S. climate and sub-climate zones, with concomitant environmental conditions and building code specifications. For CBECS, the dark bar is the median national site electricity consumption and the whiskers show the 5th and 95th percentiles.

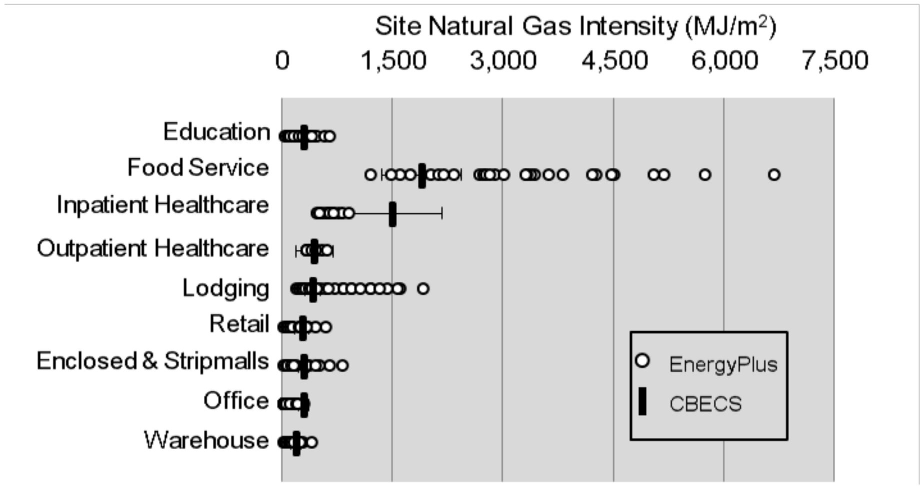


Figure 7.5. Site natural gas intensity comparison between the simulated energy consumption of building prototypes and the CBECS calculated national distribution for buildings of the building type that have been constructed since 1990 (CBECS Table C32a). The EnergyPlus output for each building type was variable because each building was simulated across all 15 U.S. climate and sub-climate zones, with concomitant environmental conditions and building code specifications. For CBECS, the dark bar is the median national site electricity consumption and the whiskers show the 5th and 95th percentiles.

7.5 Mapping CBECS and PNNL Building Types

PNNL estimates total commercial building construction at 122 million square meters per year of construction per year relative to the EIA Annual Energy Outlook reported construction in 2012 of 149 million square meters and projection of nearly 200 million square meters per year by 2020.[52]

Next we allocate this construction to the EnergyPlus building prototypes. A complicating factor is that there are estimates of state-level construction data by CBECS building type, but not by EnergyPlus building prototype.[14] Therefore we map from CBECS building types to EnergyPlus prototypes (Table 7.2**Error! Reference source not found.**). Most CBECS building ypes aggregate similar building types (for example “offices”) whereas EnergyPlus prototypes have a sub-set of categories (i.e., small, medium, and large offices). For example, nationally, CBECS office buildings are divided among small office (38%), medium office (40%), and large office (22%) EnergyPlus prototypes; we assume this ratio is constant across states.[14] With this method, we match approximately 80% of commercial building floor space constructed from 2003 through 2007 (our historical construction dataset) to EnergyPlus prototypes.

Table 7.2. Mapping CBECS and PNNL building types.

CBECS Bldg. Type	**EnergyPlus Bldg. Prototype**	**Allocation (% of CBECS)**	**% of Total Floor Space**
Office	Lg. Office	22%	3%
	Med. Office	40%	5%
	Sm. Office	37%	4%
Retail	Retail	73%	12%
	Strip mall	27%	5%
School	Primary School	33%	4%
	Secondary School	67%	8%
Healthcare	Hospital	44%	3%
	Outpatient Healthcare	56%	3%
Restaurant	Sit-down Restaurant	53%	1%
	Fast-food	47%	0%
Hotel	Lg. Hotel	74%	4%
	Sm. Hotel	26%	1%
Warehouse	Warehouse	100%	13%
Apartment	High-rise Apartment	55%	7%
	Mid-rise Apartment	45%	6%
Public Assembly	*No Prototype*		*5%*

No CBECS Type	*15%*

7.6 Climate zones by state

Figure 7.6 below shows the climate zones assumed for each U.S. county. The climate zones are also divided into three sub-climate zones: humid, dry, and marine. Most counties east of the Rocky Mountains fall into the humid sub-category. Counties west of the Rocky Mountains generally fall into the dry sub-category, except for counties along the Pacific Ocean which fall into the marine sub-category.

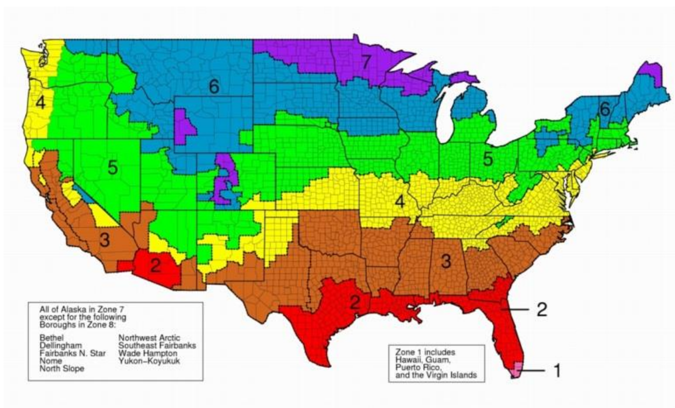


Figure 7.6. Climate zone of each U.S. county, as developed by the U.S. Department of Energy.

7.7 Population Change as a Proxy for New Commercial Building Construction

We distribute state level construction data across the climate zones within a state by using population change as a proxy for climate zone specific building construction data. The assumption that population change is an acceptable surrogate for primary construction data originated from Deru (2011): "population is a good indicator of building distribution".[25] We conduct several analyses to verify this claim: state level building construction from 2003-2007 from PNNL is regressed against state level population changes between 2000 and 2010, for total construction.[14,26] Figure 7.7 illustrates the fit using total population and total construction. We also repeat the process using construction of each building type as the independent variable. Table 7.3 provides R^2 values for each prototype. Second, we compare year 2000 population in each census regions with total commercial floor space present in each census region from the 2003 CBECS survey (Figure 7.8). We find strong evidence of a linear relationship between population change and commercial construction using the PNNL data. The analysis using the CBECS data also indicate a strong relationship between population and existing building floor area.

The relationship between population change and commercial building construction is thus used to estimate changes in building construction for each climate zone in each state. Climate zone data by county is from the U.S. Department of Energy.[24]

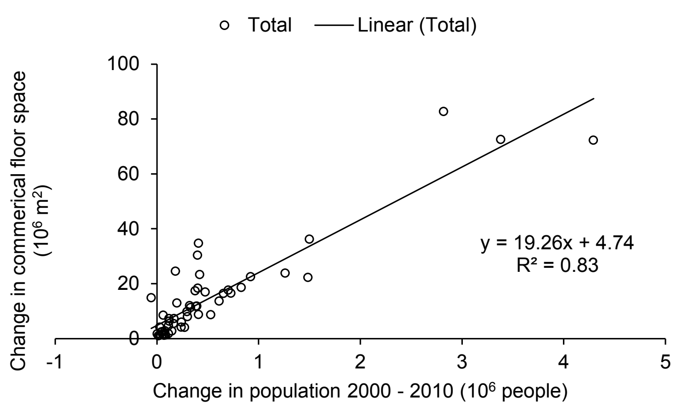


Figure 7.7. State level commercial building construction from 2003-2007 versus changes in state population between 2000 and 2010.

Table 7.3. The R^2 value when state level construction from 2003 through 2007 is explained by state level population change from 2000 through 2010.

Prototype	R^2
Apartment	0.41
Healthcare	0.70
Hotel	0.71
Office	0.86
Public Assembly	0.76
Restaurant	0.81
Retail	0.84
School	0.83
Warehouse	0.78
No Prototype	0.82

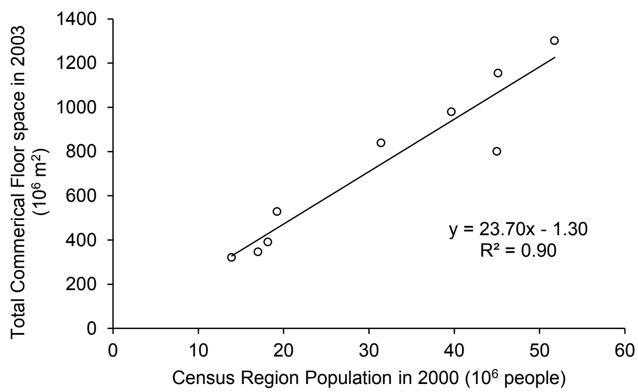


Figure 7.8. . Relationship between population and total commercial floor space, as reported in the 2003 CBECS survey.

7.8 eGRID Sub-Regions

Figure 7.9 shows the eGRID sub-regions used in the analysis.

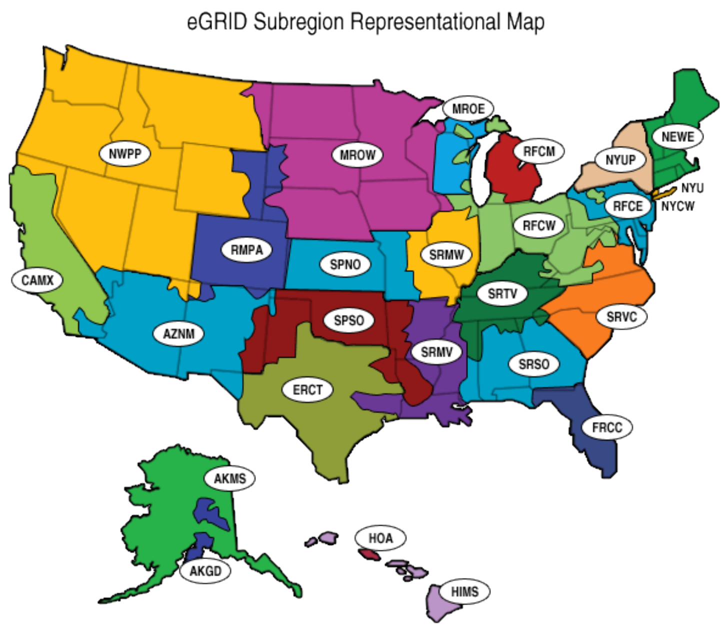
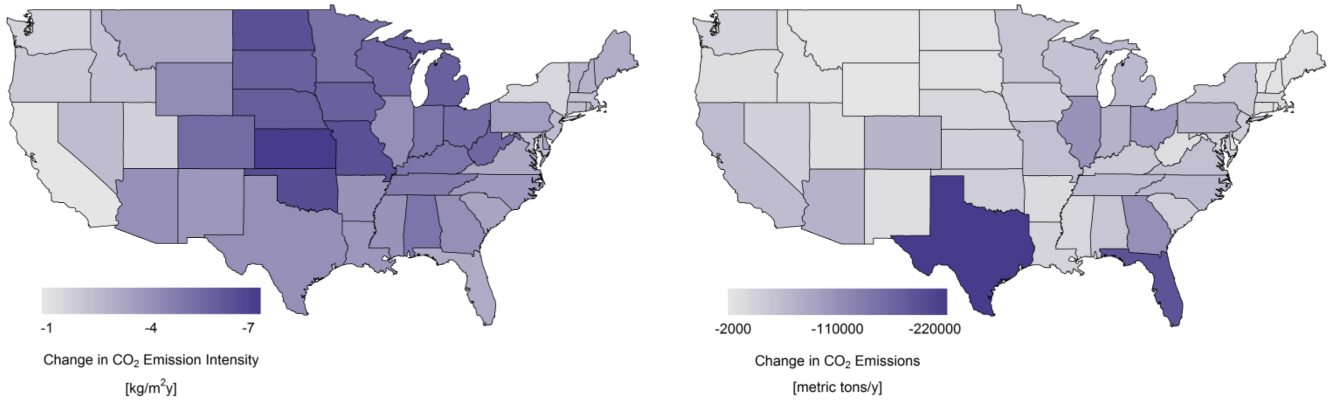


Figure 7.9. eGRID sub-regions used in the analysis. Source: [42].

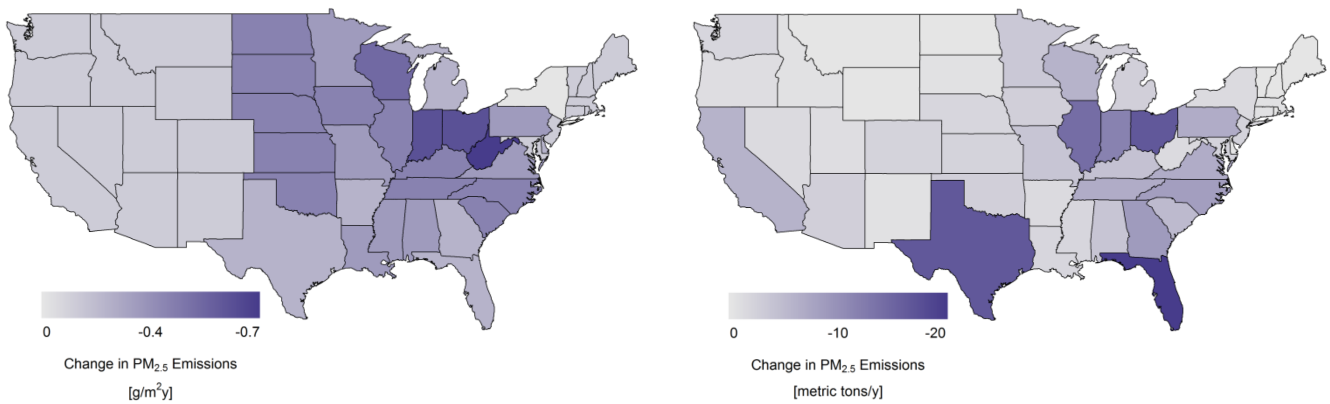
7.9 Changes in NO_x, $PM_{2.5}$, and CO_2 emissions

Potential emissions savings depend on both total construction and the emissions characteristics of electricity production in individual states. States with large amounts of construction only have large emission reductions (relative to other states) if the grid emission rate is non-negligible; states with small amounts of construction do not have large emission reductions, regardless of the grid emission rate. Figure 7.10 shows changes in CO_2, $PM_{2.5}$, and NO_x emissions.

a) b)



c) d)



e) f)

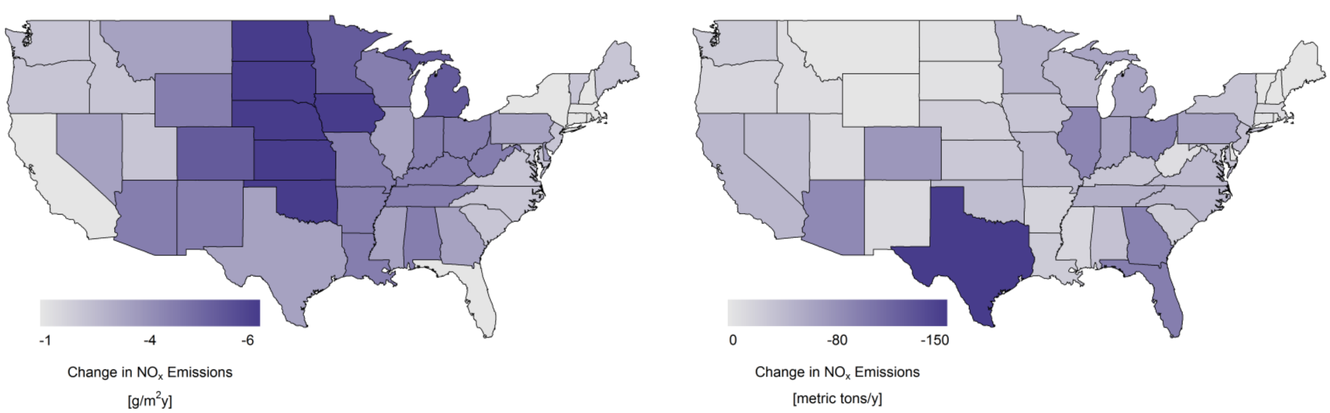


Figure 7.10. The effect of each state switching form the ASHRAE 90.1-2007 to the ASHRAE 90.1-2010 building energy code on pollutant emissions. We show emissions reductions for CO_2 (a) and (b), $PM_{2.5}$ (c) and (d), and NO_x (e) and (f).

Changes in each pollutant emission are monetized using the county level marginal pollution damages from the AP2 model and our method of averaging damages over eGRID sub-regions and then states. For reference, we include the marginal damage per ton of pollution in each eGRID sub-region (Table 7.4); sub-regions are further described in the eGRID Technical Support Document.[42]

Table 7.4. eGRID sub-region average marginal damage of pollution as calculated using the method described in the accompanying manuscript. All values are in 2010$ per metric ton.

eGRID subregion	**SO_2** *($/ton)*		**NO_x** *($/ton)*		**$PM_{2.5}$** *($/ton)*	
AZNM	$	6,527	$	3,297	$	7,994
CAMX	$	5,250	$	2,092	$	22,484
ERCT	$	8,143	$	4,317	$	14,373
FRCC	$	10,572	$	2,092	$	28,462
MROE	$	13,802	$	4,488	$	18,871
MROW	$	9,676	$	4,155	$	11,659
NEWE	$	9,495	$	747	$	25,662
NWPP	$	6,492	$	3,197	$	5,894
NYCW	$	38,023	$	9,175	$	212,607
NYLI	$	8,719	$	2,941	$	52,899
NYUP	$	12,335	$	1,670	$	20,959
RFCE	$	19,454	$	3,333	$	55,816
RFCM	$	16,019	$	2,981	$	26,708
RFCW	$	17,729	$	3,868	$	31,225
RMPA	$	6,951	$	4,264	$	8,186
SPNO	$	6,729	$	4,194	$	14,491
SPSO	$	7,133	$	4,151	$	11,213
SRMV	$	9,203	$	2,597	$	11,087
SRMW	$	14,711	$	5,703	$	22,512
SRSO	$	11,580	$	2,429	$	18,858

SRTV	$	14,192	$	3,621	$	22,339
SRVC	$	13,807	$	1,979	$	21,731

7.10 Sensitivity in Assumptions for States that Don't Currently Have ASHRAE 90.1-2007

Figure 7.11 re-creates Figure 2.3 from the main manuscript, except that the code level of those states with energy codes below the 90.1-2007 level is decreased. For the ten states that have energy codes below the 90.1-2007 code level (Arizona, Colorado, Kansas, Maine, Minnesota, Missouri, Oklahoma, South Dakota, Tennessee, Wyoming), we re-estimate energy savings, private benefits, and social benefits at the 90.1-2004 code level. This is a less stringent code level that may better represent the efficiency of new commercial buildings constructed in those states. As the figure shows, those states with energy codes that are less stringent than 90.1-2007 are likely to have higher total benefits and have a higher share of total potential benefits.

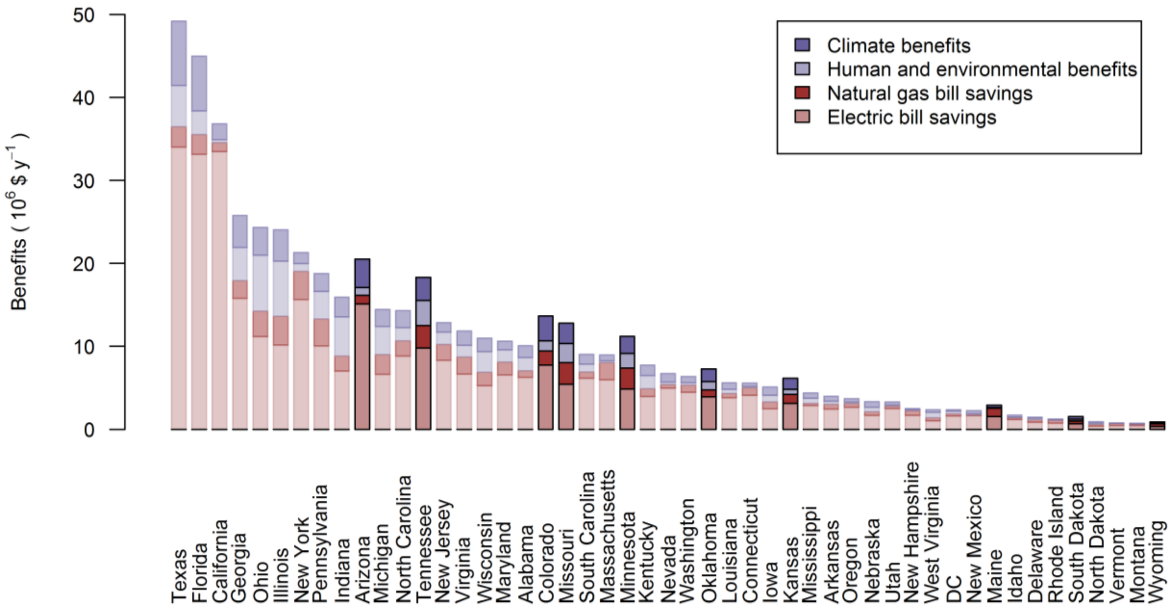


Figure 7.11. The annual benefits of the 90.1-2010 commercial building energy code for the amount of floor space constructed in each state each year. The lightly shaded bars show the benefits of switching from the 90.1-2007 to the 90.1-2010 code; states that have lightly shaded bars already have codes that meet or exceed the stringency of the 90.1-2007 code. The darker bars show the benefits of switching from the 90.1-2004 to the 90.1-2010 code; states that have darker bars have a current code level that is less stringent than the 90.1-2007 code.

Figure 7.12 shows the change in potential social benefits when we assume a 90.1-2004 as the baseline code instead of a 90.1-2007 baseline code level. We only show states that currently have codes that are less stringent that the 90.1-2007 code level. When we assume the baseline code level in each of these states is the ASHRAE 90.1-2004 code level, social benefits increase by between 30% and 40% in each state (Maine and Wyoming have slightly larger percentage increases). Across all ten states, social benefits increase by \$7.3 million per year. This is 6% of our baseline social benefits estimate of \$130 million when the baseline code level for all states is 90.1-2007.

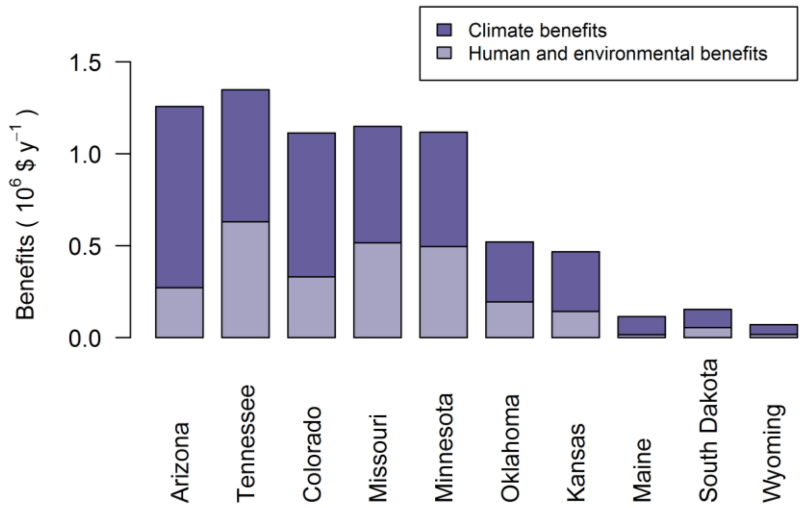


Figure 7.12. The change in annual social benefits when we assume the above states have a baseline code stringency of 90.1-2004 instead of 90.1-2007. We only show results for selected states because these are the only states whose baseline code levels are less stringent than the 90.1-2007 code. The y-axis shows 1 year of potential social benefits.

7.11 Sensitivity Analyses: Monte Carlo Methods and Results

We perform a sensitivity analysis to account for uncertainty regarding the input assumptions of the model. Specifically we vary (1) the emission rates of pollutants emitted during electricity production; (2) the allocation of buildings across buildings meeting different code levels; (3) the allocation of buildings across climate zones; and (4) the allocation of buildings across building types.

(1) Sensitivity to emission rates of pollutants emitted during electricity production: Our results are most sensitive to changes in grid emission rates, as shown in the main document. When electricity grid emission rates are set to the projected emission rates for 2020 from EIA reference case scenario, we find that social benefits decrease substantially. **Error! Reference source not ound.**Figure 7.13 shows the total social benefits for each state in the baseline and 2020 emissions projection scenario. The color scales are the same between the two figures.

Unsurprisingly, we see the largest changes in social benefits in those states that initially had the largest social benefits: Texas, Florida, Ohio, Georgia, Illinois, and Pennsylvania.

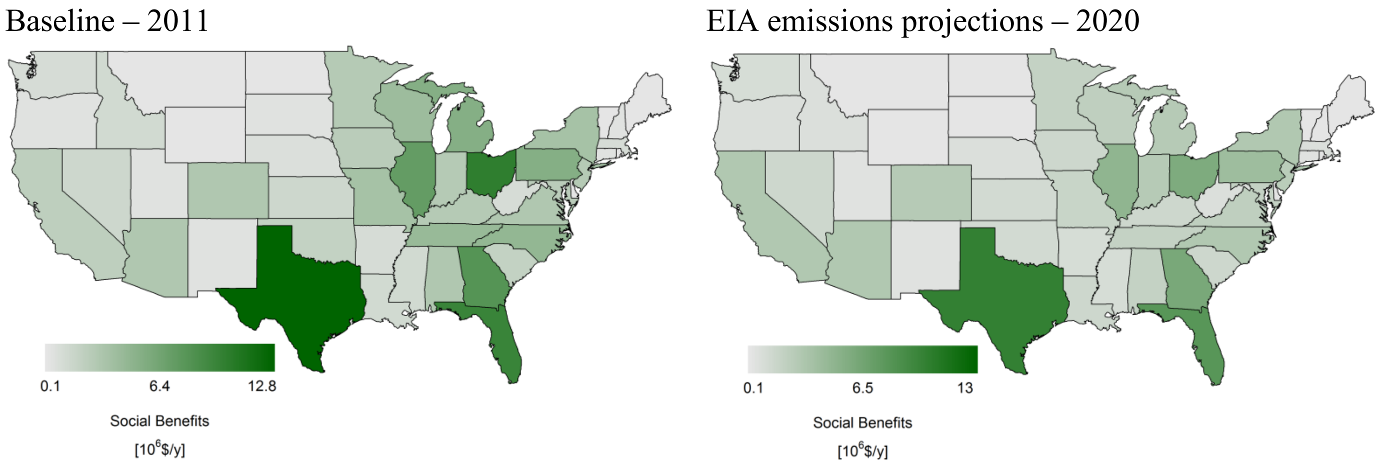


Figure 7.13. Total social benefits (million dollars per year) of a more stringent commercial building energy code for the baseline scenario, based on emission rates from 2011, and the 2020 scenario, based on emissions projections for 2020 from the EIA. The color scale for the 2020 scenario was fixed to the same range as the color scale for the baseline scenario, thus a lighter color in the 2020 scenario indicates fewer social benefits in that state.

The reduction in social benefits in the EIA 2020 reference case scenario and our 2011 scenario is primarily due to a reduction in electric grid emissions intensity for criteria air pollutants (i.e., SO_2, NO_x, and PM2.5). Carbon dioxide emission intensity also decreases, but to a lesser extent than criteria air pollutants, and the share of total social benefits derived from avoided climate change costs increases from 53% in the baseline scenario to 72% in the 2020 scenario. The fraction of total building code benefits that accrue as social benefits also decreases from 26% in the baseline scenario to 21% in the 2020 scenario. Figure 7.14 shows the total annual potential benefits of the more stringent building code when we use emission projections from 2020.

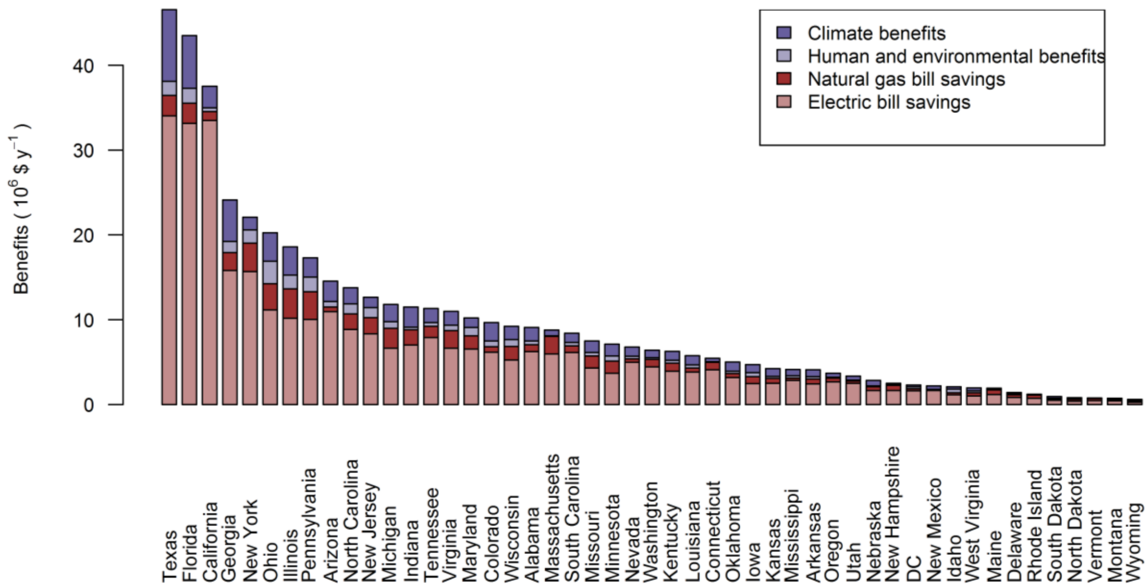


Figure 7.14. Total annual potential benefits of commercial building energy codes by state for the scenario based on emissions factors projections for 2020 from the EIA. Private benefits correspond to reductions in electricity and natural gas expenditures. Social benefits correspond to the reductions in human and environmental damages and avoided climate damages.

Lastly, we compare how social benefits in the 2020 scenario are distributed relative to the current incentive funding allocation. This assumes the goal of the incentive funding is to provide states incentive funds proportionately to the social benefits that will accrue if the state adopts a more stringent building energy code. In the baseline scenario we estimate that approximately 25% are misallocated. For the 2020 scenario we estimate that 22% of incentive funds are not allocated proportionately to potential social benefits. New York and California, due to low criteria pollutant emissions factors and relatively low carbon intensity, continue to provide a smaller share of social benefit than they receive in incentive funds. As in the baseline scenario, Texas, Florida, and Georgia continue to provide a larger share of social benefits than they receive in incentive funds. However, assuming EIA 2020 reference case projections, Ohio decrease substantially, and Ohio will change from among the least equitably incentivized states to an equitably incentivized state. Overall, differences in carbon dioxide and criteria pollutant emission rates are not accurately captured in the current incentive allocation formula, which leads somewhat inequitable incentives. Figure 7.15 shows the percentage of social benefits provided by each state and the percentage of incentives offered to each state under the EIA 2020 assumptions for grid emissions factors.

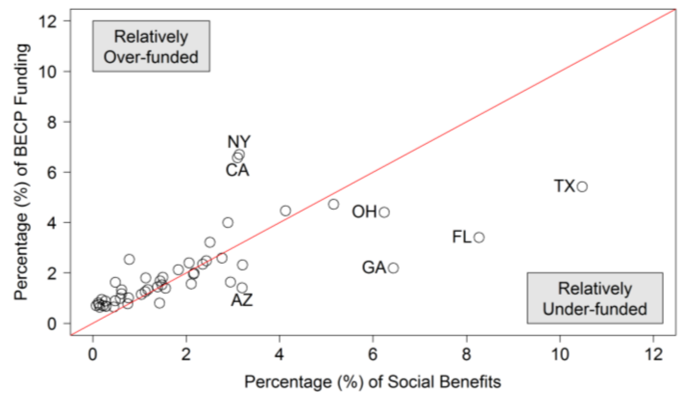


Figure 7.15 Percentage of annual Building Energy Codes Program (BECP) funding each state receives (y-axis) versus the percentage of social potential benefits, excluding private benefits (x-axis). The solid line indicates a 1:1 ratio between percentage of national benefits and percentage of national incentive funding. The distance on the y-axis between each point and the solid line shows the discrepancy between potential benefits and actual funding; points above the line show relatively over-funded states and points below the line show relatively under-funded states. The states with the largest discrepancies between funding and potential benefits are labeled.

(2) Allocation of buildings across buildings meeting different code levels: We estimate how sensitive our total energy savings are to overestimations of building energy savings under the more stringent code. To do this, we decrease the energy savings of one building type by 25% in all climate zones and re-run the model. Figure 7.16 shows that the overall effect of individual building energy savings on total energy savings. Energy savings under the more stringent 90.1-2010 code vary by building type, given the heterogeneity in the percent reduction in energy use intensity across building types (not shown). The energy savings also depends on total area of that building type constructed each year. For example, total energy savings are more sensitive to hospitals ("Health, In") than restaurants despite larger savings in restaurants because of the difference in annual construction.

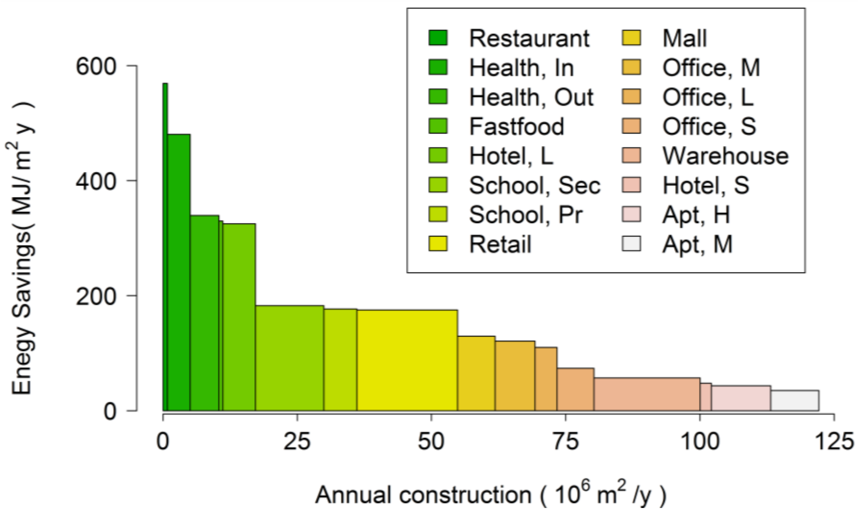


Figure 7.16. Shows the annual construction of each building type (width of bars on the x-axis) and the energy savings intensity of each building type (height of bars on y-axis). The area of each bar represents the total energy savings contributed by each building type in the baseline model (savings per area times area constructed).

(3) Allocation of buildings by climate zone: We change the distribution of new construction across state climate zones changing the fraction of construction that occurs in the 'primary' climate zone and proportionately increasing or decreasing the fraction of new construction that takes place in all other climate zones. The climate zone that initially has the largest fraction of new construction is designated as the primary climate zone; for most states, the primary climate zone initially accounts for more than 75% of all new construction. We then change the fraction of new construction in the primary climate zone from about 30% to 100% and re-run the model multiple times. Our findings are largely insensitive to changes in the climate zone and indicate that uncertainty regarding the distribution of construction across states is not a sensitive model parameter.

(4) Allocation of buildings across building types: We change the mix of buildings that comprise new construction by changing the fraction of new floor space that a random group of buildings accounts for and proportionately redistributing that floor space across the remaining building types. We perform a Monte Carlo simulation where we randomly choose the amount of floor space to reallocate in each model run. The magnitude of the change ranges from decreasing the floor space fraction of building types by 50% to increasing the fraction by 50% (i.e., a uniform distribution from a 50% reduction from current floor space to a 50% increase from current floor space). We rerun 10,000 times and estimate the elasticity of results for each scenario.

We report the sensitivity of our results as an elasticity, which we calculate as the percentage change in the model results divided by the percentage change in the input parameter of interest (Equation 6.1). Elasticity can be interpreted as a measure of how sensitive the results are to changes in input parameters[18]. In economics, an elasticity of less than one (larger than negative one) normally designate inelastic or inflexible results and an elasticity of larger than one indicate more elastic or flexible results. Figure 7.17 shows the elasticity of state level energy savings to changes in the building mix. For over 80% of all scenarios run (i.e., the 10th to the 90th percentile of scenarios) state level results all have an elasticity of between -1 and 1. Thus, a random change in the building mix of 'x' percent nearly always changes results by less than 'x' percent. Further, we observe both increases and decreases in benefits as the building mix changes. Therefore, we conclude that our reported results are not highly sensitive to the building mix that was constructed from 2003 through 2007.

$$Elasticity = \frac{\%Change\ in\ Benefits}{\%\ of\ New\ Construction\ Re-allocated} \tag{6.1}$$

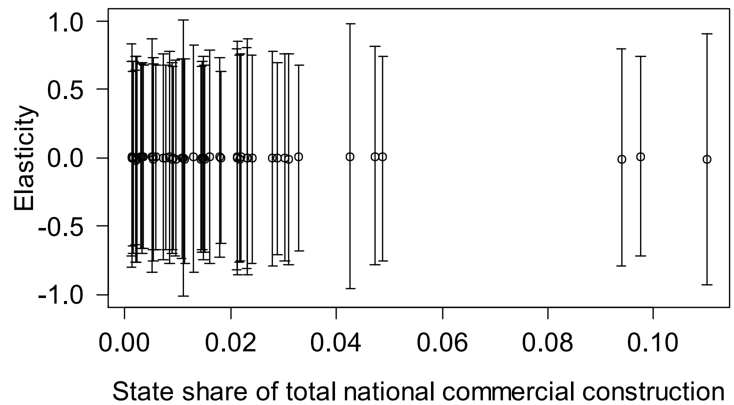


Figure 7.17. Elasticity of state-level energy savings to changes in the types of commercial buildings construction within that state. The state median elasticity for the 10,000 Monte Carlo runs is the hollow marker, with the error bars showing the 10th and 90th percentile of runs.

8 Appendix 2: Chapter 3 Supplemental Information

8.1 Legal / Policy Basis for Implementing Efficiency Programs in Each State

Table 8.1. The stance of each state in New England towards utility sponsored energy efficiency programs.

State	Stance on Efficiency	Source
Connecticut	Increase the amount of cost effective efficiency that is captured	[68]
Maine	Implement cost effective efficiency programs as approved by the PUC	[58]
Massachusetts	Capture all cost effective efficiency	[70]
New Hampshire	Implement cost effective efficiency programs as approved by the PUC	[72]
Rhode Island	Capture all cost effective efficiency	[69]
Vermont	Increase the amount of cost effective efficiency that is captured	[179]

Notes:

[1] Connecticut General Assembly, "Chapter 283, Section 16-245m."

[2] Efficiency Maine Trust, "Triennial plan for fiscal years 2014-2016," 2012.

[3] The General Court of the Commonwealth of Massachusetts, "An Act relative to green communities," 2008.

[4] New Hampshire Public Utilities Commission, "Order establishing guidelines for post-competition energy efficiency programs," 2000.

[5] Rhode Island General Assembly, "R.I.G.L. § 39-1-27.7."

[6] Vermont General Assembly, "30 VSA 218c."

8.2 Estimating the natural gas savings of natural gas efficiency programs using EnergyPlus

We simulate the natural gas consumption of commercial buildings in New England using commercial building prototypes from Pacific Northwest National Laboratory (PNNL) as input into the EnergyPlus building energy simulation model [7,20]. The PNNL prototypes are 16 "typical" commercial buildings that PNNL states are appropriately representative of 80% of new commercial building construction and about two-thirds of existing commercial buildings [7,14]. PNNL also created specific versions of each prototype to comply with three ASHRAE building energy code standards and each of the 16 climate-zones in the US. Since all of New England lies in climate zones 5 and 6, excepting a small part of northern Maine, we represent commercial buildings using building prototypes that comply with building code standards for these climate zones. Finally, we use the ASHRAE 90.1-2004 building energy code as the base case (i.e. no-efficiency) scenario efficiency level. This represents a middle ground between potentially less stringent older energy codes and the slightly more stringent 90.1-2007 building energy code [7].

Next we simulate the natural gas consumption of each building prototypes over one year in EnergyPlus. Gilbraith et al. (2014) state: "EnergyPlus is a freely available building energy simulation model created by the Department of Energy (DoE) [19]. EnergyPlus simulates the energy consumption of a building over a chosen time period (e.g. 1 year) using input files that specify building characteristics and weather data (i.e., the building prototypes mentioned above). EnergyPlus performs heat balance calculations at each time step to determine energy losses (e.g. loss through walls, windows, and floors) and gains (e.g. solar insolation through windows, heat gain from lighting/equipment) [20]. The characteristics of building systems, such as furnace or air conditioner technology types and efficiencies, determine the amount of electricity or natural gas needed to maintain the desired indoor conditions. Indoor conditions are specified in building operating schedules. Operating schedules also define building characteristics such as thermostat set points, occupancy, equipment operation, and lighting schedules. EnergyPlus also models other (smaller) energy transfers, including heat gain due to lighting and occupancy [19]." From the output of EnergyPlus, we then calculate the natural gas consumption per square foot of building floor space. This allows us to weight natural gas savings based on the fraction of total existing commercial building floor space of each building type.

Estimating the distribution of existing commercial buildings in New England

Our analysis assumes that buildings participate in efficiency programs in proportion to their share of total commercial floor space. Thus, the natural gas savings from office building efficiency program participation, which account for a larger share of total floor space than fast food restaurants, receive proportionately more weight than the natural gas savings from fast food efficiency program participation. We rely on this assumption since we do not have data on the distribution of buildings that participate in natural gas efficiency programs. However, utilities with such data may consider estimating the capacity value of efficiency programs based on the specific mix of buildings that participate in their efficiency programs.

In order to us to estimate the proportion of total commercial building floor space that each EnergyPlus building prototype represents, we use data from the Commercial Building Energy Consumption Survey (CBECS) and the Pacific Northwest National Laboratory (PNNL) [14,22]. CBECS provides existing commercial building floor space data at the census region level (i.e. the Northeast census region which includes the New England and Middle Atlantic census divisions). Neither the 2003 or 2012 CBECS survey reported the amount of existing commercial building floor space for the New England census division due to sample size limitations. We map this 2003 CBECS data to EnergyPlus prototypes using a mapping scheme developed by PNNL and applied in Gilbraith et al. (2014) [14,22,89]. Generally, the mapping scheme breaks down broader CBECS categories (such as office buildings) into the smaller EnergyPlus prototypes (such as small, medium, and large offices) using PNNL's nationwide commercial building construction dataset that runs from 2002-2007 [14,89]. Due to the existence of many less common commercial building types, neither the CBECS survey nor the EnergyPlus prototypes cover 100% of the commercial building stock; literature suggests that the EnergyPlus prototypes represent approximately two-thirds of the existing commercial building stock [14,89].

8.3 Baseline and Higher Efficiency Scenario Equipment Efficiencies

Table 8.2 shows the thermal efficiency values for the base case, high efficiency and very high efficiency scenarios in the manuscript. We assume equipment efficiency levels do not vary across states. While the minimum efficiency standards of efficiency programs do vary slightly across, our results (in the Results section of the manuscript) show that the efficiency level of the equipment has a very small effect on the capacity value of the efficiency program. Thus, our decision to simplify minimum equipment efficiency levels to a single value across all New England states is reasonable.

Second, states also report the minimum efficiency program qualifying efficiency levels using multiple units. These are thermal efficiency (i.e. combustion efficiency), annual fuel utilization efficiency, and energy factor. We provide the definition of each below. The various definitions of efficiency provide insight into the efficiency of individual system components vs. overall system efficiency or identify which losses the calculation includes. Given that the capacity value of efficiency programs is not sensitive to the efficiency level chosen, we judge that using a single efficiency metric (which may not perfectly capture different in equipment requirements across states) is reasonable for our analysis.

Table 8.2. Building equipment efficiency for the base case, high efficiency (HE) and very high efficiency (VHE) scenarios. We assume the values remain constant across states. Base case efficiency values are the 90.1-2004 code compliant efficiency levels as found in the Pacific Northwest National Laboratory EnergyPlus building prototypes.[7] All efficiency values we report are the thermal efficiency of the equipment.

	Base case	High Efficiency	Very High Efficiency
Boiler	0.793*	0.87	0.95
Furnace	0.8†	0.95	0.97
Hot water heater	0.8	0.95	-

*: Efficiencies in individual building prototypes range from 0.75 – 0.793

†: Efficiencies in individual building prototypes range from 0.793 – 0.8

Definitions:

Combustion Efficiency: 100 percent of efficiency minus the percentage of heat lost up the vent.

Thermal Efficiency: The combustion efficiency minus the jacket losses of the boiler.

Annual fuel utilization efficiency: The measure of annual efficiency of a boiler that takes into account the cyclic on\off operation and associated losses as it responds to changes in load.

Energy Factor (EF): A measure of water heater overall efficiency, is the ratio of useful energy output from the water heater to the total amount of energy delivered to the water heater

8.4 Validation of the Relationship Between Efficiency Savings and Natural Gas Demand

In order to validate the assumption that natural gas demand is perfectly correlated with efficiency program energy savings, we compare natural gas demand with efficiency program energy savings data. Since daily natural gas demand data for utilities in New England is not available, we predict demand using an estimated regression from National Grid (Massachusetts) service territory in combination with weather data [81]. National Grid reports that over the past eight years their regression equations explain demand extremely well, with a minimum R^2 value of 0.9769 (Figure 8.1). We use weather data for Boston, Massachusetts to predict demand [90]. This is the same weather data that is used to estimate efficiency program natural gas savings in the EnergyPlus simulation model [90]. Energy efficiency program natural gas savings is the state averaged natural gas savings of the high efficiency furnace efficiency intervention. Figure 8.2 compares predicted natural gas demand with simulated natural gas savings. We observe that efficiency program natural gas savings have a high Pearson's correlation coefficient (r = 0.931), corroborated by the visual likeness of the data.

National Grid provides the following explanation for the regressions presented in Figure 8.1:

> *"The Company developed a linear-regression equation using data for the reference-year period April 1, 2011 through March 31, 2012. Its regression equation uses sendout as its dependent variable and temperature as its independent variable. Through the use of the linear-regression equation, the Company is able to normalize daily sendout. Specifically, the actual daily firm sendout is regressed against effective degree day ("EDD") data as provided by its weather service vendor WSI, EDD data lagged over two days, and a weekend dummy variable. These data elements were selected for the regression analysis since these elements have been, and continue to be, the major explanatory variables underlying National Grid daily sendout requirements".*

Boston

Segmented Regression Results for Boston sendout vs. EDD and Weekend and Lagged Delta EDD

Split Year	Intercept	Slope1	Slope2	Weekend	Lagged Delta EDD	Standard Error	Adjusted R^2	Breakpoint EDD
2004/05	82,389.4	1,874.1	9,498.8	-6,362.2	-1,976.5	17,960	0.9886	8.302
2005/06	86,998.9	1,548.6	9,416.7	-10,046.6	-1,644.9	22,290	0.9769	8.137
2006/07	87,314.5	1,571.2	10,414.7	-9,103.6	-1,950.1	18,960	0.9867	9.374
2007/08	90,662.5	2,298.8	9,935.6	-8,681.0	-1,940.7	18,910	0.9859	10.200
2008/09	88,072.4	2,154.5	10,231.7	-8,655.3	-2,142.4	20,110	0.9866	10.500
2009/10	86,731.8	2,272.9	10,380.3	-7,931.1	-2,091.6	15,720	0.9906	10.110
2010/11	91,551.9	2,108.7	10,548.7	-7,661,6	-2,179.3	16,150	0.9917	9.399
2011/12	95,510.2	2,257.0	10,493.0	-7,633.3	-2,208.6	17,640	0.9846	9.192

Figure 8.1. The table produced by National Grid in their Long Range Resource and Requirements Plan that shows natural gas demand (sendout) is explained extremely well when effective degree days (EDD) and a weekend dummy variable are used as independent variables.

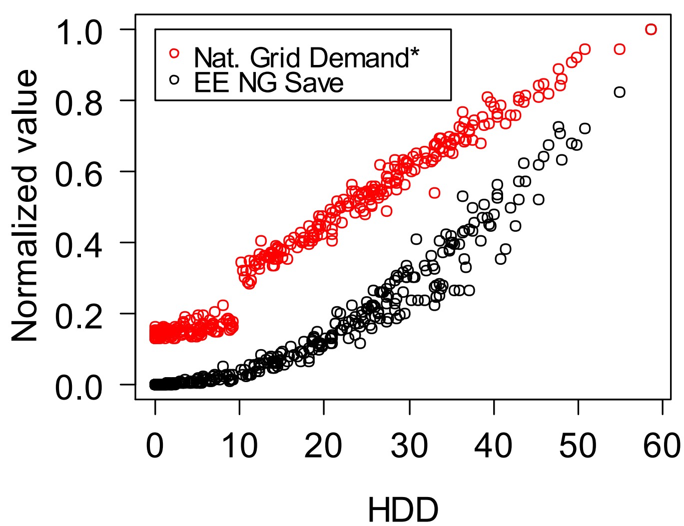


Figure 8.2 shows natural gas demand versus simulated natural gas savings the EnergyPlus simulations. Natural gas demand data is predicted natural gas demand in the National Grid (Massachusetts) service territory using the same Boston, Massachusetts weather data we use to estimate building natural gas savings. National Grid reports that their demand estimation regressions predict natural gas demand with an R^2 of greater than 0.979. The simulated natural gas savings is natural gas savings for the high efficiency furnace intervention in Boston, Massachusetts. The correlation coefficient between the data is 0.931.

8.5 Deriving the Volume of Firm Capacity Avoided by Natural Gas Efficiency Programs

Goal: identify an expression for the firm pipeline capacity value of a natural gas efficiency program

Table 8.3. The variables we use when identifying an expression for the firm pipeline capacity value of a natural gas efficiency program.

Variable	Definition
d	Natural gas utility natural gas demand
p	Natural gas utility consumption of peaking supplies
F	Natural gas utility total firm pipeline capacity
f	Natural gas utility pipeline flow
s	Natural gas efficiency program natural gas savings
n	Number of days peaking resources are used
c	Firm pipeline capacity value of the natural gas efficiency program

Table 8.4. The subscripts we use when identifying an expression for the firm pipeline capacity value of a natural gas efficiency program.

Subscript	Definition
t	Time index
$*$	Days when peaking resources are used

Table 8.5. The superscripts we use when identifying an expression for the firm pipeline capacity value of a natural gas efficiency program.

Superscript	Definition
‘ (apostrophe)	Post efficiency intervention

Assume: total energy consumption of peaking supplies does not increase over the period of peaking resource use (n days):

$$\sum_{n} p_t == \sum_{n} p_t'$$

Given energy consumption of peaking supplies equals total demand minus pipe flow (also minus efficiency in the efficiency scenario):

$$p_t = d_t - f_t$$

$$p'_t = d_t - f'_t - s_t$$

Then:

$$\sum d_t - f_t = \sum d_t - f'_t - s_t$$

Breaking summations apart:

$$\sum d_t - \sum f_t = \sum d_t - \sum f'_t - \sum s_t$$

Simplify (we want to solve for new pipe flow, f'):

$$\sum f'_t = \sum f_t - \sum s_t$$

Assume pipe flow is constant (e.g., at max capacity) over the period that the utility uses peak resources. At this point, we only begin to ignore non-peaking days (i.e. days from n+1 to 365):

$$\sum f'_{t,*} = n * f'_{t,*}$$

$$\sum f_{t,*} = n * f_{t,*}$$

Substituting and dividing by ‘n’ (number of days peaking resources are used):

$$f'_{t,*} = \frac{\sum f_{t,*} - \sum s_{t,*}}{n}$$

Simplifying

$$f'_{t,*} = f_{t,*} - \overline{s_{t,*}}$$

Thus, new pipeline capacity equals average pipeline flow over the period that the utility uses peaking resources the average energy savings of the efficiency program over the same period.

If we define the firm capacity value of the natural gas efficiency program as the difference in pipe flow during peak demand periods between the base and efficiency scenarios:

$$c = f_{t,*} - f'_{t,*}$$

Substituting:

$$c = \overline{s_{t,*}}$$

Therefore, capacity savings of the efficiency program equal the average savings of the efficiency program over the period of peaking resource use.

8.6 Deriving the Change in Capacity Resale Due to a Natural Gas Efficiency Program

Goal: identify an expression to calculate the change in the quantity of excess capacity that the utility resells between the base case and efficiency scenarios.

Table 8.6. The variables we use when identifying an expression for the change in excess capacity resale that occurs due to a natural gas efficiency program.

Variable	Definition
d	Natural gas utility natural gas demand
r	Natural gas utility excess capacity resale
F	Natural gas utility total firm pipeline capacity
f	Natural gas utility pipeline flow
s	Natural gas efficiency program natural gas savings
T	Total number of time periods (all time periods, not just peaking days)
c	Firm pipeline capacity value of the natural gas efficiency program
Δ	Change in natural gas utility excess capacity resale between two scenarios

Table 8.7. The subscripts we use when identifying an expression for the change in excess capacity resale that occurs due to a natural gas efficiency program.

Subscript	Definition
t	Time index
$*$	Days when peaking resources are used

Table 8.8. The superscripts we use when identifying an expression for the change in excess capacity resale that occurs due to a natural gas efficiency program.

Superscript	Definition
‘ (apostrophe)	Post efficiency intervention

We note that:

Capacity value of efficiency (defined in Section 5, above):

$$c = \overline{s_{t,*}}$$

Firm pipeline capacity after efficiency (by definition):

$$F' = F - c$$

We assume that excess capacity resale is equal to the difference between the total firm pipeline capacity of the natural gas utility and the daily natural gas demand of the utility:

$$r_t = F - d_t$$

Thus, annual excess capacity resale equals:

$$\sum_t r_t = \sum_t F - d_t$$

Daily natural gas demand, after efficiency:

$$d_t' = d_t - s_t$$

Annual excess capacity resale, after efficiency:

$$\sum_t r_t{}' = \sum_t F' - d_t{}' = \sum_t (F - c) - (d_t - s_t)$$

Change in total capacity resale:

$$\Delta = \sum_t r_t' - r_t$$

Substituting:

$$\Delta = \left(\sum_t (F - c) - (d_t - s_t)\right) - \left(\sum_t F - d_t\right)$$

Expanding:

$$\Delta = \sum_t F - \sum_t c - \sum_t d_t + \sum_t s_t - \sum_t F + \sum_t d_t$$

Simplifying:

$$\Delta = -\sum_t c + \sum_t s_t$$

Recognizing that the capacity value of the efficiency program does not vary throughout the year:

$$\Delta = -T * c + \sum_t s_t$$

Replacing the capacity value of the natural gas efficiency program with the equivalent expression (derived earlier in the SI) in terms of the natural gas savings of the efficiency program

$$\Delta = \ -T * \overline{s_{t,*}} + \sum_t s_t$$

Given:

$$\overline{s_t} = \frac{\sum_t s_t}{T}$$

Then:

$$\Delta = \ -T * \overline{s_{t,*}} + T * \overline{s_t}$$

$$\Delta = \ T * \left(\overline{s_t} - \overline{s_{t,*}}\right)$$

We see that the change in excess capacity resale will depend on whether the mean daily efficiency savings over the year is larger or smaller than the mean daily efficiency savings during the peak period (period of off-system resource use). The mean daily savings over the peak period will be larger than the annual mean daily savings for peak coincident efficiency measures (such as space heating efficiency programs) and thus these programs will result in a net decrease in excess capacity resale. The mean savings over the peak period will be approximately equal to the annual mean for baseload efficiency measures (such as hot water heater programs) and thus these programs will result in a minimal change in excess capacity resale.

Figure 8.3 visualizes the change in the quantity of excess pipeline the capacity resells due to an efficiency program. We observe that during periods when the utility uses less than its full firm capacity, the utility can resell the difference between total firm capacity and demand. Thus, when the utility owns less firm capacity (relative to a base case), the utility sells less excess capacity in most time periods (red striped area). On the other hand, the efficiency program decreases natural gas demand relative to the base case. This increases excess capacity resale in most time periods.

a) b)

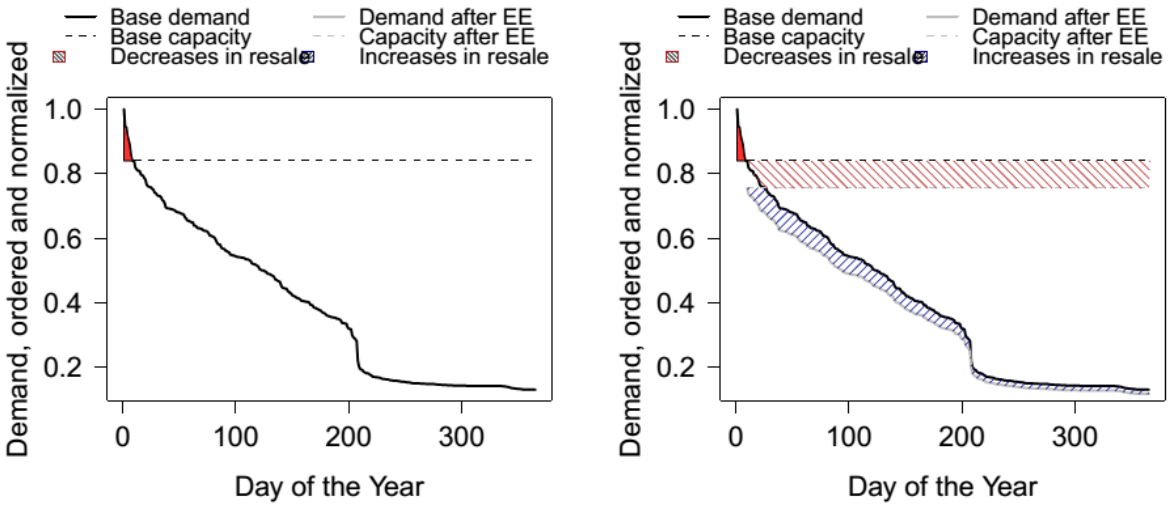


Figure 8.3. How an efficiency program changes utility excess capacity resale due to the change in firm capacity the utility owns and the change in the natural gas demand of the utility. a) shows the base case and b) shows the effect of the efficiency program.

8.7 Monetary Value of Excess Capacity Resale

We convert changes in excess capacity resale to changes in revenue using the market value of short-term pipeline capacity from the Marcellus Shale region to New England. Based on MacAvoy (2007), we assume the value of short-term pipeline capacity is equal to the difference in prices (basis) between Marcellus Shale pricing points and New England (the Algonquin Citygates pricing point) [102]. One factor this assumption does not account for how uncertainty in future natural gas prices affects the value of natural gas pipeline capacity [180]. However, since we parameterize the value of short-term capacity in the Sensitivity Analysis, we use the basis differential as the base case value of short term capacity. Figure 8.4 shows futures natural gas prices for both pricing points from Natural Gas Intelligence [181]. The difference the two lines is the monetary value we assign to each thousand cubic feet of short term capacity resale. Substantial basis differentials exist during the winter months for all five years of futures data. For years six through fifteen of the efficiency program, we assume that basis differentials remain constant and equal to those of the last twelve months of data.

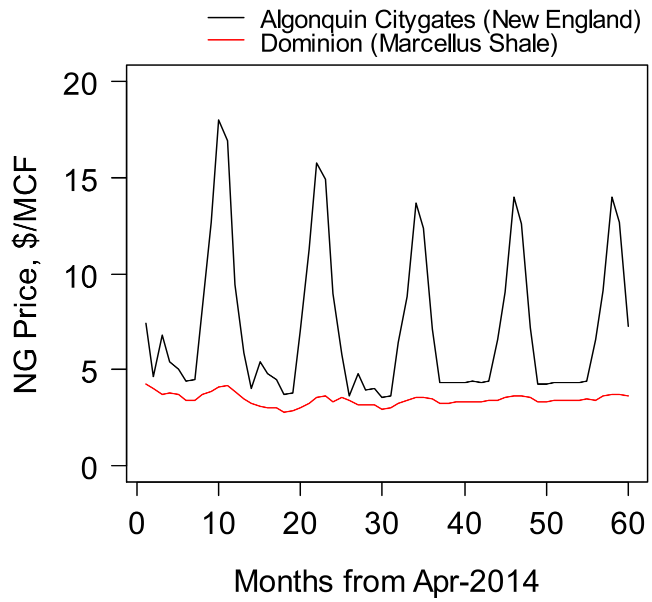


Figure 8.4. Futures natural gas prices from April 2014 through March 2018 (5 years of monthly data). Data is from Natural Gas Intelligence "Forward Look" [181].

We also perform a "sanity check" to ensure that we can reasonably assume that the value of short term pipeline capacity will equal the commodity price difference between two natural gas pricing points.

Can we assume that the value of short term pipeline capacity is equal to the price basis between two pricing points?

Define some variables:

Ai Price of natural gas at a price point outside NE

B Price of natural gas at price point in NE

Ti Price of transporting natural gas from price point Ai to B. We define this as the market price of transporting gas from Ai to B.

Hypothesis: the value of short term pipeline capacity is equal to the basis price between two pricing points plus the market price of transporting natural gas between the two points.

B – Ai = Ti OR:

B = Ai + Ti

Scenario 1: Assume the price differential between Ai and B is greater than Ti

B – Ai > Ti

Is the same as

B > Ai + Ti

Market participants can purchase gas outside New England (Ai) and purchase pipeline capacity into New England (Ti) at a lower cost than the current New England market price (B). The market participant makes arbitrage profits of B – (Ai + Ti) without risk and would (rationally) continue to do so until the price in New England converges with the price outside of New England plus the price of pipeline capacity into New England. Thus we assume the difference between prices outside New England and inside New England will not exceed the price of pipeline capacity between the two locations.

Scenario 2: Assume the price differential between Ai and B is less than Ti

$B - A_i < T_i$

Is the same as

$B < A_i + T_i$

It is cheaper for market participant to purchase gas within New England rather than to purchase gas outside New England and transport the gas into New England. However, New England does not have any "indigenous" sources of natural gas; suppliers import all natural gas from one of a variety of sources. Two outcomes are possible:

1) Market participants are unwilling to pay the market price for transporting gas into New England because the price of gas outside New England plus the market price of transport exceeds the market price in New England. As consumers continue to use natural gas and limited local (i.e. stored) supplies decrease, prices in New England will increase until they equal the price of gas outside New England plus transport costs. B converges to equal Ai + T. Thus we assume the difference between prices outside New England and inside New England will not be less than the price of transporting natural gas between the two locations.

2) Market participants are utilizing other sources of natural gas, with lower supply plus transport costs, to meet demand in New England. For example, LNG or imports from Canada (simply different Ais and Tis) as opposed to pipeline capacity from the Marcellus shale. In this case, for pipelines where Ai + Ti is greater than B (which we assume will equal the Ai + Ti of the cheapest supply plus transport combination), owners of pipeline capacity may be willing to reduce the price they charge for their pipeline capacity until it equals either a) the difference between B – Ai or b) the variable cost of using the pipeline capacity (nearly zero). This is because if the pipeline owners do not do so, then market participants do not utilize their

more expensive pipeline and the pipeline owners forgo all revenues. Thus we assume the difference between prices outside New England and inside New England will not be less than the price of transporting natural gas between the two locations.

Either way, we expect that supply and demand will reach an equilibrium where the price of gas in New England converges to be equal to the cheapest Ai + Ti available, which will be the revenue received by all of the Ai + Ti combinations.

8.8 Validating that the distribution of efficiency program natural gas savings across the year we obtain from EnergyPlus is reasonable

Figure 8.5 shows the daily natural gas savings of each type of natural gas efficiency program as a percentage of the total annual natural gas savings of that program ordered from largest to smallest. The shaded regions show the range of efficiency program savings across the New England states and across the High and Very High equipment efficiency levels. The location of the program is the primary source of variability in the distribution of program savings across the year; the difference between the High and Very High equipment efficiency levels is minimal. In general, however, the distribution of natural gas savings across the year is not highly sensitive to the specific location within New England or the difference between the High and Very High efficiency levels.

Both space heating programs (furnaces and boilers) have similar distributions of natural gas savings across the year, albeit with furnaces providing a slightly higher fraction of total savings during peak savings periods. On the other hand, the distribution of natural gas savings across the year is noticeably different between space heating efficiency programs and hot water heating efficiency programs. Space heating efficiency program natural gas savings are highly skewed because the majority of natural gas savings occurs during the winter months when buildings use space heating equipment. Hot water heating efficiency program natural gas savings are relatively constant because buildings consume hot water throughout the year.

We use the Connecticut Program Savings Document (PSD; Connecticut's version of a Technical Reference Manual) to validate the distributions of our savings estimates. The Connecticut PSD reports that furnace and boiler efficiency programs have peak day savings of 1.5% and 1.3% of annual savings, respectively [22]. We estimate that furnace and boiler programs in Connecticut have peak day savings of 2.1% and 1.5%, respectively. Further, we estimate that furnace programs savings, in particular, decrease rapidly: savings on the third highest savings day equal 1.7% of annual savings. The magnitude of Connecticut PSD and our estimates are therefore in the same ballpark.

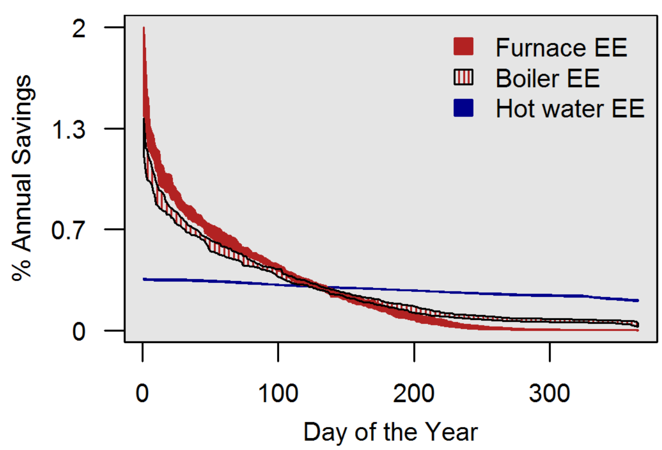


Figure 8.5. The daily natural gas savings of each efficiency program as a percentage of total annual savings, ordered from highest to lowest. The sum across all days equals 100% of the program annual natural gas savings. The shaded area shows the full range (min. to max.) savings across the seven cities we use to represent the six New England states and the two equipment efficiency levels (High and Very High). Efficiency programs are represented by shaded areas, and not a single lines, because the savings of a given efficiency program vary slightly based on the location within New England and the equipment efficiency level. However, our results indicate that geographic variability is much larger than variability between the High and Very High equipment efficiency levels.

8.9 Firm Pipeline Capacity Savings due to Natural Gas End-Use Efficiency Programs

In Scenario 1 (No Capacity Shortfall) the utility does not expect to purchase additional firm pipeline capacity to meet demand. Since utilities must pay for all existing firm capacity contracts, the utility does not avoid firm capacity purchases due to natural gas efficiency programs. In Scenario 2 (Capacity Shortfall), the change in firm capacity requirements is the mean daily quantity of natural gas saved over the number of days that the utility uses off-system peaking resources to meet demand (Equation 3.1 from the Methods section of the main manuscript).

Table 8.9. The firm pipeline capacity purchases that each MCF of natural gas savings over the life of the efficiency program provide. We show results for three scenarios: when the utility uses off-system peaking resources for 0, 10, and 20 days each year. All other model inputs are the base case inputs from Table 3.4in the Methods section of the main manuscript.

		Volume of firm capacity avoided (CF/d)			Present value of firm capacity avoided per MCF of program savings ($)		
	Program	**0**	**10 †**	**20**	**0**	**10†**	**20**
Scenario 1 (No Capacity Shortfall)	Boiler	0.0	0.0	0.0	0.00	0.00	0.00
	Furnace	0.0	0.0	0.0	0.00	0.00	0.00
	Hot water heater	0.0	0.0	0.0	0.00	0.00	0.00
Scenario 2 (Capacity Shortfall)	Boiler	0.8	0.7	0.6	$4.18	$3.49	$3.15
	Furnace	1.2	0.9	0.8	$5.75	$4.47	$3.94
	Hot water	0.2	0.2	0.2	$1.13	$1.13	$1.12

heater

†: Number of days that off-system peaking resources are used in the base case

8.10 Utility Capacity Shortfall Analysis

We performed a review of natural gas utility planning documents for utilities in New England to determine whether they were facing capacity shortfalls. Table 8.10 shows the utilities we identified as natural gas utilities in New England, the annual demand of each utility, and whether or not the utility has indicated they a capacity shortfall. We find that the majority of utilities (by total demand) in southern New England face a capacity shortfall while utilities in northern New England do not. We did not find data for majority of natural gas utilities in Maine. Further, press reports indicate that natural gas utilities in Maine are seeking to expand the natural gas system in Maine [182]. Thus we recommend the Maine Public Utilities Commission determine whether utilities in Maine will face a capacity shortfall before using our recommended avoided costs.

Table 8.11 shows results condensed by state and region within New England.

Table 8.10. Lists all utilities we identified as natural gas utilities in New England and provides relevant information related to whether each faces a capacity shortfall.

State	Name	Doing business as (DBA)	Annual Demand / Planning Load (2012)	Unit	Shortfall	Source
MA	Bay State Gas	Columbia Gas of MA	40.16	BCF	Yes	[183]
MA	Berkshire Gas		6.22	BCF	No	[184]
MA	Blackstone Gas		0.17	BCF	No	[185]

MA	NSTAR Gas		41.72	BCF	Yes	[100]
MA	New England Gas Company	Liberty Utilities	5.89	BCF	Yes	[186]
MA	Fitchburg Gas and Electric Co.		1.95	BCF	No	[187]
MA	National Grid	Boston Gas / Colonial Gas	116.3	BCF	Yes	[81]
CT	Connecticut Natural Gas Corporation		30.47	BCF	Yes	[85,188]
CT	Southern Connecticut Gas Company		27.45	BCF	Yes	[85,188]
CT	Yankee Gas Services Company		48.7	BCF	Yes	[85,188]
RI	National Grid		33.1	BCF	Yes	[189]
NH	Liberty Utilities/ EnergyNorth		13.4	BCF	No	[80]
NH	Northern Utilities	Unitil	5.36	BCF	No	[190]
VT	Vermont Gas Systems		6.17	BCF	Yes	[191]
ME	Northern Utilities	Unitil	4.88	BCF	No	[190]
ME	Bangor Gas	Energy West	Not found	n/a	n/a	n/a
ME	Maine Natural Gas Corporation		Not found	n/a	n/a	n/a
ME	Summit Natural Gas of Maine		Not found	n/a	n/a	n/a

Table 8.11. A summary of natural gas utility capacity shortfall information by state and New England region. *Note: we have incomplete data for Maine and press reports suggest that Maine natural gas utilities are seeking to expand the natural gas system to serve new customers in the future.Note: the "capacity shortfall" percentage is a natural gas demand weighted average of the capacity shortfall (= 100%) and no capacity shortfall (= 0%) determinations from Table 8.10.**

Location	Capacity shortfall**
CT	100%
MA	96%
RI	100%
Southern NE	98%
ME *	0%
NH	0%
Northern NE	0%
VT	100%
Total NE	**92%**

8.11 The capacity value of natural gas energy efficiency programs by state

As we discuss in the Methods section of the main manuscript, we use the building energy simulation model EnergyPlus to estimate the natural gas savings of efficiency measures in each state. To estimate the state level natural gas savings profile, we estimate the natural gas savings of the efficiency program in the largest city within each climate zone of each state and assume these are representative profiles for the whole state. The slightly different climactic conditions across the states in New England have a nearly negligible effect on the overall capacity value of the natural gas efficiency programs (Table 8.12).

Table 8.12. The net present capacity value of each MCF of natural gas efficiency program natural gas savings for each New England state, excluding Vermont.

Region	**Space Heating Programs**	**Non-space heating programs**
	Net present capacity value of each MCF of program savings ($/MCF)	
Southern New England	-$2.4	$0.8
Connecticut	*-$2.3*	*$0.8*
Massachusetts	*-$2.5*	*$0.8*
Rhode Island	*-$2.4*	*$0.8*
Northern New England	$4.7	$2.7
Maine	*$4.7*	*$2.7*
New Hampshire	*$4.8*	*$2.8*

8.12 Value of Natural Gas Purchases Avoided by End-Use Efficiency Programs

We reproduce Exhibit 2-20 from the 2013 AESC report below (Figure 8.6). The AESC reports all natural gas prices in 2013$. The AESC report uses a reference real discount rate of 1.36%, thus we obtain the present value of natural gas by discounting 2013 natural gas prices in each year to the present at 1.36%. The values shown in Table 8.13 are the present value of avoiding one MCF of natural gas consumption in each year. We estimate the levelized avoided natural gas purchase value (i.e. for each unit of natural gas that the efficiency program saves) by multiplying and then summing the natural gas savings and the present value of natural gas savings in each year, which we then divide by the total number of MCF the efficiency program saves (Equation 7.1 below). Conservatively, we chose a levelized value of $5/MCF for natural gas savings for all programs. In choosing a levelized value of natural gas savings at the high end of those that the AESC reports, our total avoided costs and benefit cost ratio will also be at the high end of those that we could reasonably estimate using the AESC data.

Exhibit 2-20. Natural Gas Wholesale Price Forecasts, 2013$/MMBtu

Year	Henry Hub	Appalachia	TETCO M3	Dawn	New England
2013	3.84	3.75	4.13	4.19	6.35
2014	4.12	4.01	4.42	4.47	5.98
2015	4.15	4.03	4.44	4.50	5.75
2016	4.18	4.03	4.44	4.53	5.14
2017	4.50	4.30	4.74	4.85	4.91
2018	4.77	4.59	5.05	5.11	5.24
2019	5.01	4.84	5.33	5.36	5.53
2020	5.34	5.16	5.68	5.69	5.90
2021	5.48	5.27	5.80	5.83	6.02
2022	5.77	5.48	6.03	6.11	6.26
2023	5.95	5.61	6.18	6.30	6.41
2024	6.07	5.71	6.29	6.41	6.52
2025	6.26	5.92	6.52	6.61	6.76
2026	6.41	6.03	6.64	6.76	6.89
2027	6.58	6.16	6.78	6.93	7.04
2028	6.69	6.26	6.89	7.03	7.15

Figure 8.6. Exhibit 2-20 from the 2013 Avoided Energy Supply Costs in New England report. [56]

$$a_{levelized} = \frac{\sum_t s_t * \sum_t PV_{ng,t}}{\sum_t s_t} \qquad (7.1)$$

Where 'a' is the levelized present value of each MCF of natural gas that the efficiency program saves, 's' is the natural gas savings of the efficiency program in each time period, 'PV' is the present value of natural gas in each time period, and the subscript 't' is the annual time index.

Table 8.13. The present value of avoiding one MCF of natural gas consumption in each year, based on the 2013 AESC nominal natural gas price data and a real discount rate of 1.36%. We show a levelized avoided cost based on avoiding an equal quantity of natural gas consumption in each year.

Year	Present Price				
	Henry Hub	Appalachia	TETCO M3	Dawn	New England
2013	$ 3.84	$ 3.75	$ 4.13	$ 4.19	$ 6.35
2014	$ 4.06	$ 3.96	$ 4.36	$ 4.41	$ 5.90
2015	$ 4.04	$ 3.92	$ 4.32	$ 4.38	$ 5.60

2016	$	4.01	$	3.87	$	4.26	$	4.35	$	4.94
2017	$	4.26	$	4.07	$	4.49	$	4.59	$	4.65
2018	$	4.46	$	4.29	$	4.72	$	4.78	$	4.90
2019	$	4.62	$	4.46	$	4.92	$	4.94	$	5.10
2020	$	4.86	$	4.69	$	5.17	$	5.18	$	5.37
2021	$	4.92	$	4.73	$	5.21	$	5.23	$	5.40
2022	$	5.11	$	4.85	$	5.34	$	5.41	$	5.54
2023	$	5.20	$	4.90	$	5.40	$	5.50	$	5.60
2024	$	5.23	$	4.92	$	5.42	$	5.52	$	5.62
2025	$	5.32	$	5.03	$	5.54	$	5.62	$	5.75
2026	$	5.38	$	5.06	$	5.57	$	5.67	$	5.78
2027	$	5.45	$	5.10	$	5.61	$	5.74	$	5.83
2028	$	5.46	$	5.11	$	5.63	$	5.74	$	5.84
levelized @ 1.36% real	**$**	**4.76**	**$**	**4.55**	**$**	**5.01**	**$**	**5.08**	**$**	**5.51**

8.13 Updating the benefit to cost ratio of natural gas efficiency programs

The benefit to cost ratio is simply the present value of the benefits of the efficiency program divided by the present value of the cost of the efficiency program. Assuming that the present value of the costs of the efficiency program does not change according to the method that the PUC uses to calculate the benefits of the program (a seemingly logical assumption), we can update the current benefit to cost ratio as follows:

Table 8.14. The variables we use when identifying an expression for the firm pipeline capacity value of a natural gas efficiency program.

Variable	Definition
r	Benefit to cost ratio
b	Benefits

c	Costs

Table 8.15. The subscripts we use when identifying an expression for the firm pipeline capacity value of a natural gas efficiency program.

Subscript	Definition
AESC	The current benefit to cost ratio for natural gas efficiency programs that PUCs have accepted.
2	Our estimates of the total avoided costs of natural gas energy efficiency programs and the implied benefit to cost ratio.

Defining the benefit cost ratio using current values:

$$r_{AESC} = \frac{b_{AESC}}{c_{AESC}} \tag{i}$$

And rearranging:

$$c_{AESC} = \frac{b_{AESC}}{r_{AESC}} \tag{ii}$$

Defining the same equation using our values:

$$r_2 = \frac{b_2}{c_{AESC}} \tag{iii}$$

And rearranging:

$$c_{AESC} = \frac{b_2}{r_2} \tag{iv}$$

Setting (ii) and (iv) equal (thus, we assume that the utility's cost to run the efficiency program does not change between the two scenarios):

$$\frac{b_2}{r_2} = \frac{b_{AESC}}{r_{AESC}} \quad \text{(v)}$$

Finally, we rearrange and obtain Equation 3.3 from the main manuscript:

$$r_2 = \frac{b_2}{b_{AESC}} * r_{AESC} \quad \text{(vi)}$$

9 Appendix 3: Chapter 4 Supplemental Information

9.1 Cost of a distributed solar PV array

Table 9.1. Retail prices for distributed solar PV arrays from solar PV vendors in Portugal.

System	FFSolar		Esite		King solar		Solar Impact		CCBS	
	system	install	system	Install	system	install	system	install	system	install
200 W	€ 650	-	€ 393	€ 150	-	-	-	-	€ 400	€ 400
250 W	€ 662	-	-	-	€ 330	-	€ 350	-	€ 410	€ 400
500 W	€ 1,115	-	€ 763	€ 193	€ 585	-	€ 700	-	€ 680	€ 400
750 W	€ 1,568	-	€1,119	€ 236	€ 980	-	-	-	-	-
1000 W	-	-	€1,482	€ 280	€1,165	-	-	-	€ ,350	€ 400
1500 W	€ 2,274	-	€2,247	€ 366	€1,745	-	€2,180	-	€2,020	€ 400

Data are from:

http://ffsolar.com/

http://esite.pt/

http://kingsolar.pt/

http://www.solarimpact.pt/

http://www.ccbs-energia.pt/

Last checked: June 19th, 2015

9.2 Analysis of Portuguese Electricity Demand

When residential consumers install solar photovoltaic panels, the electricity system has the potential to avoid part of the cost of serving that consumer. From a transmission and distribution perspective, if solar panels help to reduce demand during peak periods, solar PV may have the potential to mitigate the cost of meeting existing peak demand levels or help defer investment to meet growing peak demand levels. In order to determine whether solar PV in Portugal has the potential to reduce system peak demand, we identify the timing and seasonality of peak electricity demand (Figure 9.1). We observe that peak demand in Portugal general occurs during the winter months and that both afternoon and late evening periods tend to have the highest electricity demand. While more high demand hours are in the late evening, the highest electricity demand since July 10, 2010 (9,887 MW) occurred at 11:00am on February 9, 2015. The highest electricity demand in the evening (9,791 MW) occurred on February 2, 2015.

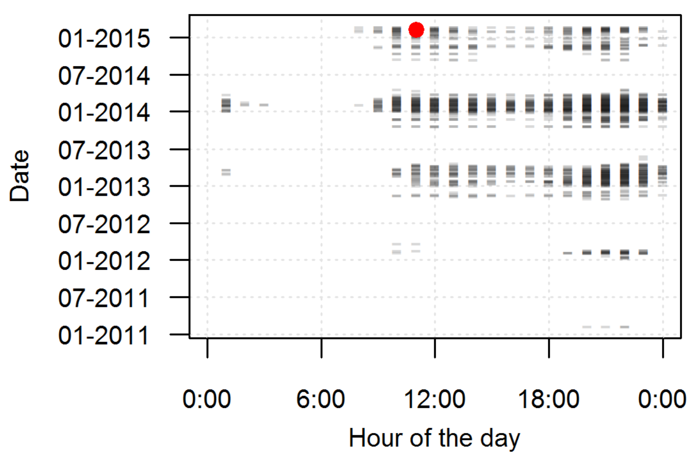


Figure 9.1. The timing and seasonality of peak electricity demand in Portugal. Each semi-transparent black dash indicates one hour of demand. We show the top 5% of all demand hours since July 10, 2010. The location of the dash corresponds to the hour (x-axis) and date (y-axis) of the demand. The red point shows the highest peak hourly demand (9,887 MW) since July 10, 2010. Demand data is for Portugal and obtained from the Iberian Electricity Market Operator (OMIP).

Next we use our solar PV generation model to determine the capacity factor of solar panels during peak demand periods. The meteorological data we use to estimate solar PV generation runs from April 2012 through mid-September 2014 and therefore we limit our comparison to this date range. Figure 9.2 shows the 20 highest demand days over this period and the corresponding solar PV generation. Demand is normalized (max demand over the data series is equal to 1) and solar PV output is based on a 1kW array (rated output at reference conditions). Thus solar output can be interpreted as the capacity factor of solar during peak demand periods. We observe that the sun has already set during the late evening peak electricity demand and thus solar cannot reduce system peak demand during these periods. Solar PV does produce electricity during the day, but output varies widely across the peak demand days from approximately 15% of rated capacity to 50% during the peak afternoon hours. Given this variability, solar PV cannot be credited with a large capacity factor during afternoon peak demand periods because transmission and distribution infrastructure are designed based on a chosen loss of load probability. Even using our limited data, solar PV has a relatively high probability of not performing, or performing at a very low capacity factor, during peak demand periods.

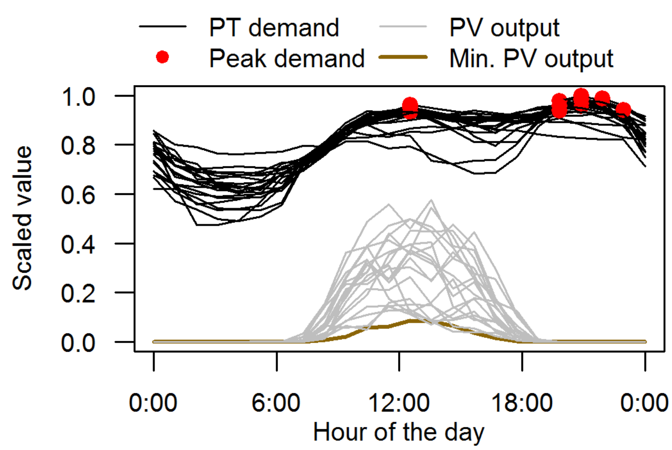


Figure 9.2. Hourly system electricity demand from REN over the 20 highest demand days and the corresponding solar output based on meteorological conditions in Lisbon, Portugal on those same days.

Based on our limited demand and solar PV generation data, we observe that the technical potential for peak demand reductions across all of Portugal due to solar PV is 96 MW. If afternoon demand is reduced by any greater amount, then the evening peak demand becomes highest system peak demand. This technical potential also assumes that afternoon peak demand will not be naturally exceeded by evening peak demand, which could occur given the larger number of peak demand hours during the evening (Figure 9.2 above). Thus our analysis of peak demand suggests that solar PV may be able to play a very limited role in reducing system peak demand.

Given that solar PV only has the potential to reduce peak demand by approximately 1%, in our base case we assume that residential solar PV does not offset any transmission or distribution system costs. However, we recommend that regulators continue to monitor the installation of solar PV systems in order to account for pockets where the penetration of solar may be sufficiently large to reduce local peak demand.

9.3 Background information on Portuguese low-voltage electricity tariffs

The Portuguese electricity system changed substantially between 2010 and 2015. Overall Portuguese electricity demand, which was 47,837 GWh (gigawatt-hours; 1 GWh = 1,000 MWh) in 2010, fell 9.1% to 43,464 GWh by 2014.[122,139] The Portuguese electricity regulator (Entidade Reguladora dos Serviços Energéticos; ERSE) projects that demand will increase slightly in 2015, however, ERSE over-predicted demand growth in each of the past four years [139–142,155,168,169,192]. Additionally, total annual payments from consumers to electricity system participants (e.g., generators, transmission and distribution companies) increased by about 1 billion Euro (nominal; 18% of initial costs) over this period. In order to understand these trends in the context of residential electricity consumers, we briefly characterize changes in electricity system costs, changes in residential consumer electricity prices and demand, and changes in Portuguese energy policies that occurred over the past five years.

Additionally, we identify the factors that caused residential electricity prices to increase, and whether these factors are likely to lead to additional price increases in the future. We use total consumption by normal low voltage consumers as a proxy for residential electricity consumption. To assess changes in residential electricity prices, we assume the total sum residential consumers pay for electricity is the fraction of total costs that the Portuguese government implicitly or explicitly choses to recover from residential consumers multiplied by the total electricity system cost (Equation 8.1). The average residential tariff is then the residential share of total electricity system costs divided by the product of the number of un-subsidized residential electricity consumers and the average consumption of each un-subsidized residential electricity consumer (Equation 8.2).

$$C_{res} = C_{sys} * f_{res} \tag{8.1}$$

$$\overline{t_{res}} = \frac{C_{res}}{n * \overline{q_{res}}} \tag{8.2}$$

Where C_{res} is the total amount residential consumers pay, C_{sys} is the total system cost, f_{res} is the residential fraction of system costs, t_{res} is the mean residential tariff, n is the number of un-subsidized residential ratepayers, and q_{res} is the annual average quantity of electricity a residential consumer uses.

The total cost of the Portuguese electricity system

Until recently, Portugal had a traditional electricity system. Centralized electricity generators inject electricity into a transmission network. The transmission network delivered energy to high voltage, medium voltage and low voltage networks. Some very large consumers connected directly to the high voltage network; however, most consumers connected to the medium or low voltage network. Demand side resources and energy efficiency were a low priority for the system regulator (ERSE) and thus had small budgets.[122] Demand did not change substantially over the past ten years.

Despite flat demand for electricity and existing generation, transmission, and distribution infrastructure, the annual cost of the Portuguese electricity system increased substantially over the past ten years. Electricity system consumers pay a part of the cost increase and the remaining fraction contributes to a large and growing "tariff deficit". Specifically, since 2010 the annual amount that Portuguese consumers pay for electricity increased from about five billion Euro to about six billion Euro, or an 18% increase. Demand fell by 4,300 GWh (9%) over this same period.[122,168,169] Additionally, beginning in 2006, the revenue the electricity system collected from consumers did not cover the total costs of the electricity system. The Portuguese government chose avoid allowing rates to increase by an amount that would cover total costs and thus allowed a tariff deficit to occur. ERSE expects the cumulative deficit to exceed 5 billion Euro by the end of 2015, not including additional costs that the Portuguese government shifted into the future.[113,122]

Payments made by consumers

Figure 9.3 shows the total revenue that ERSE allows the transmission company, the distribution companies, and the grid management company to recover for each year since 2010.[122,139–142,155] These revenues exclude any system costs that consumers do not pay (i.e. the tariff deficit). These revenues do include energy costs that regulated companies pass through from consumers to generators. Consumer payments totaled 5.25 billion Euro (nominal) in 2010. The largest change in consumer payments between 2010 and 2015 is the 1.1 billion Euro increase in pass-through payments to revenue guaranteed generators. Revenue guaranteed generators are Special Regime Generators ('Producão em Regime Especial'; renewable energy generators and some co-generation facilities; SRGs[122]), CMEC generators ('custos para a manutenção do equilibrio contratual'; generators that relinquished their power purchase agreements in order to participate in the wholesale electricity market and, in exchange, receive payments from the electricity system[193]), and CAE generators ('contratos de aquisição de energia'; generators that did not relinquish their power purchase agreements but participate in the wholesale electricity market and, in exchange, receive the difference between the value of their PPA and the revenue they receive in the market[156]). Of these three, gross obligations (i.e. not consumer payments into the system) to Special Regime Generators increased the most, from 0.8 billion Euro in 2010 (nominal) to 1.6 billion Euro in 2015[122,155]. For reference, this 0.8 billion Euro increase corresponds to 21% of the total revenue that the system collected in 2010. Over the same period, the annual revenue that consumers paid to special regime, CMEC, and CAE generators increased by 1.1 billion Euro (nominal). Thus, total growth in revenue collected from consumers exceeded total growth in revenue promised to special regime generators increase, However, because ERSE did not allow special regime generators to recover their full guaranteed revenues in 2010, ERSE still projects a 2015 tariff deficit of approximately 0.4 billion Euro.

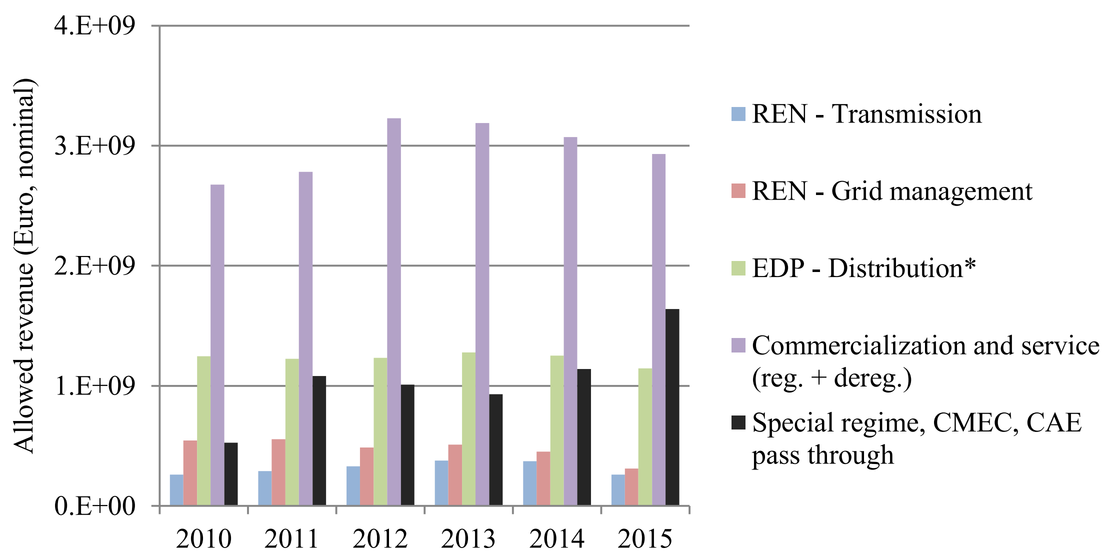


Figure 9.3. The costs that ERSE allows electricity consumers to pay (i.e. the revenue ERSE allows electricity system participants to collect) by category. Data are from [122,139–142,155]. The actual revenue that each electricity system participant collects will vary slightly because ERSE demand projections do not exactly represent actual demand. Note: the revenue

that commercialization agents recover is the revenue for both regulated (e.g. default service provider) and deregulated service providers. *In the source data, EDP Distribution revenues include the revenue passed through to SRG, CMEC, and CAE generators. For clarity, we separate EDP Distribution revenue into the revenue EDP Distribution passes through for SRG, CMEC, and CAE generators and all other revenue.

Figure 9.3 also shows that the transmission, distribution, and grid management components of total allowed revenue fell 0.32 billion Euro (nominal) between 2010 and 2015. This decrease corresponds to 6% of the total revenue that the system collected in 2010. The reduction in allowed revenue between 2014 and 2015 accounts for the entire reduction in allowed revenue over the entire period (i.e., costs did not change from 2010 through 2014). It is interesting to note that demand fell for five years while the distribution, transmission, and grid management companies recovered the same amount of revenue. On the other hand, ERSE decreased the allowed revenue of those companies for 2015 while also projecting demand to increase by 2.7%. Therefore it is unclear whether, or to what degree, the reduction in system demand from 2010-2014 led to the reduction in the allowed revenue between 2014 and 2015.[122]

Finally, Figure 9.3 shows that the cost of commercialization and serving electricity consumers increased 0.26 billion Euro (nominal) relative to 2010. This increase corresponds to 5% of the total revenue that the system collected in 2010. During this period the commercialization and service market changes from a primarily regulated system to a primarily de-regulated system.[122,139–141,155] Thus it is not clear how the cost of commercialization and service will evolve in the future.

The tariff deficit

The tariff deficit covers the difference between the amount that ERSE allows consumers to pay and the total amount that ERSE (or the policies of the Portuguese government) promises to generators. Table 9.2 shows the annual and cumulative tariff deficit since 2010. In addition to the deficits that Table 9.2 shows, ERSE or governmental legislation also deferred electricity system costs in ways that do not show up in the deficit. For example, the Portuguese government passed Decree-Law 35/2013 which extends the lifetime of the feed-in-tariff subsidy for renewable generators if those generators agreed to make a small payment in the present.[194] Peña, Azevedo and Ferreira (2014) show that Decree-Law 5/2013 increases the net present value of the subsidy given to renewable energy generators, over a wide range of discount rates and other assumptions, because the present value of extending the duration of the feed-in-tariff is substantially larger than the payment the generators must make in order to extend the feed-in-tariff.[113] ERSE projects the cumulative tariff deficit will be 5.08 billion Euro at the end of 2015, which equals 82% of 6.22 billion Euro in total payments that ERSE projects all consumers will make in 2015.[122]

Table 9.2. The Portuguese tariff deficit.

Year	Outstanding (10^9 Euro, nominal)		Cumulative (10^9 Euro, nominal)		Source
2006	*		€	-	[123]
2007	€	0.15	€	0.15	[123]
2008	€	1.33	€	1.49	[123]
2009	**		€	1.49	[123]
2010	**		€	1.49	[123], [195]
2011	**		€	1.49	[123]
2012	€	0.75	€	2.24	[123]
2013	€	1.27	€	3.51	[123]
Other	€	0.16	€	3.68	[123]
2014***	€	1.01	€	4.69	[122]
2015****	€	0.39	€	5.08	[122]

* ERSE reports the outstanding debt on the combined 2006/2007 tariff deficit. For simplicity, we assign the debt to only 2007.

** ERSE reports that tariff deficits occurred in 2009-2011 but that the Portuguese government deferred these deficits over 15 years.

*** ERSE reports the total tariff deficit in 2014 is 4.69 billion Euro, thus we subtract the 2013 debt plus "Other" debt from the total 2014 debt to calculate the 2014 Portuguese tariff deficit

**** ERSE projects the total tariff deficit in 2015 will be 5.08 billion Euro, thus we subtract the 2015 projected debt from the total 2014 debt to calculate the 2015 Portuguese tariff deficit

The fraction of total system costs that low voltage consumers pay

Residential consumers typically connect to the normal low voltage network (Baixa Tensão Normal; BTN). This is also the voltage class for some small commercial consumers. Figure 9.4 shows total electricity demand for each voltage class, including the normal low voltage class. We observe that the electricity demand of low voltage consumers fell 17% (3,575 GWh) between 2010 and 2014. The reduction in low voltage consumer electricity demand accounts for almost all of the 9% reduction in total electricity system demand.

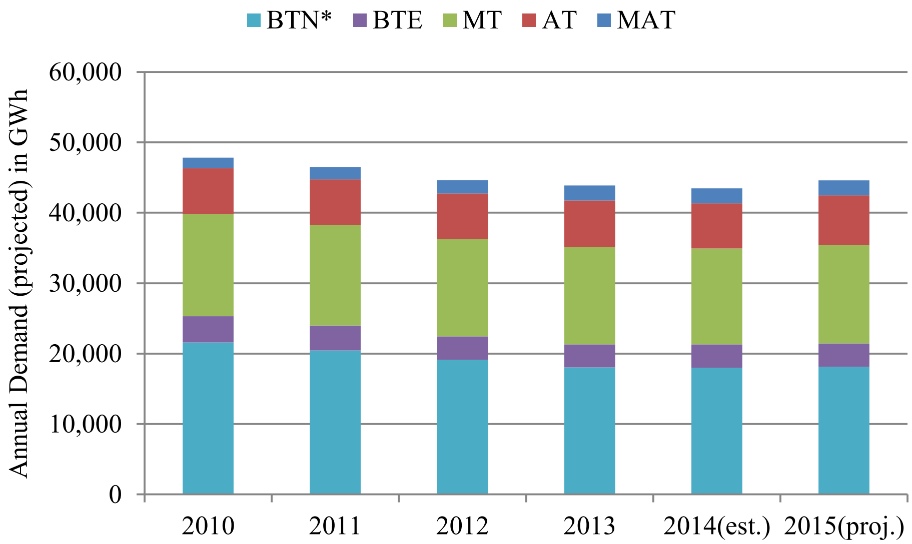


Figure 9.4. Portuguese annual electricity consumption at each voltage level. ERSE reports that most residential consumers fall into the "BTN" (Baixa Tensão – Normal; normal low voltage) category. BTE – Special low voltage class; MT – medium voltage class; AT – high voltage class; MAT – very high voltage class.

Figure 9.5 shows the low voltage consumer share of total system costs versus the low voltage consumer share of total demand. In 2010, low voltage consumers paid about two thirds of total system costs. The fraction of total system costs that low voltage consumers paid decreased slightly between 2010 and 2014 but ERSE projects that the low voltage consumers' share of total electricity system costs will increase to 60% in 2015. We calculate the "rate" at which low voltage consumers pay into the electricity system by dividing the low voltage consumer fraction of total system costs by the low voltage consumer fraction of total electricity use. We find that the ratio equaled 1.45 in 2010, was slightly lower from 2011-2014, and, based on the projections from ERSE, will return to 1.45 in 2015.

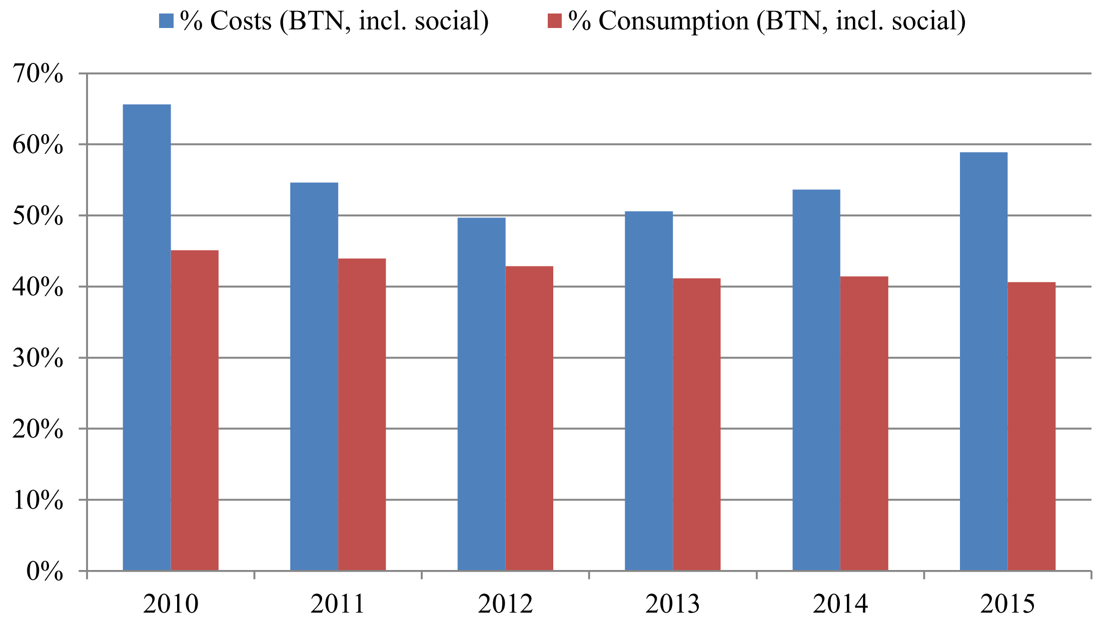


Figure 9.5. The low voltage consumer share of total Portuguese electricity consumption and low voltage consumer share of total electricity bills. We estimate residential consumer expenditures by multiplying total low voltage consumption by the average residential tariff. Consumption data are from [168,169,192]. Tariff data are from [139–142,155]. We subtract the subsidy that economically vulnerable consumers receive from total BTN revenues (i.e. the loss of revenue from the social tariff and the electricity bill subsidy). Data on the loss of revenue due to the social tariff are from [122,139–142,155] and data on the electricity bill subsidy are from [196,197].

Additionally, since ERSE began publishing the statistic in 2013, all low voltage customers pay approximately 60% of the total "custos de política energética, ambiental ou de interesse económico geral (CIEG)" (Figure 9.6). CIEG costs are the costs associated with Portuguese energy and environmental policies, which are primarily the supplemental revenue that the Portuguese government promised to special regime, CMEC, and CAE generators.[122,141,142] Thus based on the implicit or explicit policies of the Portuguese government, low voltage consumers consistently pay both total system costs and energy policy at a slightly higher rate than other rate classes (i.e. pay more of each cost per unit of consumption than other rate classes). Further, while low voltage consumers' fraction of system costs varied over the past five years, no evidence suggests that ERSE will allocate future increases in system costs differently.

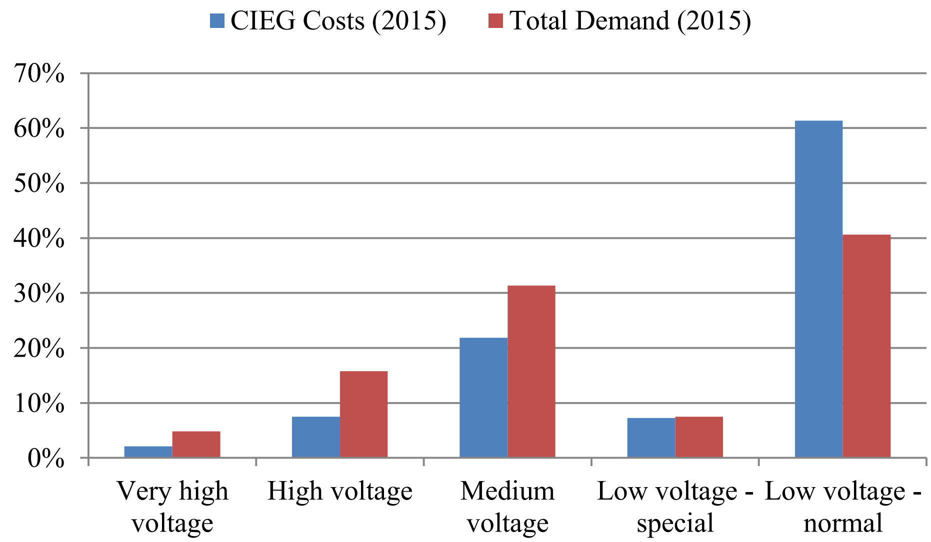


Figure 9.6. The share of the total energy, environmental, and "other economic" (CIEG) costs that each class of consumer pays and the share of total electricity demand of each class of consumer. Data are from [122].

The number of un-subsidized low voltage consumers

If ERSE seeks to recover a certain fraction of total electricity system costs from low voltage consumers, then, all else equal, if the number of low voltage consumers decreases then the average price low voltage consumers pay will increase. Similarly, if ERSE places some low voltage consumers into subsidized rate classes with a lower electricity price, then, all else equal, unsubsidized consumers may pay more.

To start, population growth between 2000 and 2010 increased the potential number of residential consumers by approximately 1%. The Portuguese census does not project large increases in future population. Thus low voltage consumers will not realize lower or higher rates due to population trends. Second, the Portuguese government instituted two policies that shift consumers from unsubsidized to subsidized rate classes. The first policy reduces the fixed charge (connection fee) consumers pay each month. Centralized electric generators make payments to cover the cost of this policy and thus the policy has the potential to increase rates (albeit indirectly) if generators then pass these costs back to unsubsidized consumers. However, ERSE projects the connection fee subsidy will cost thirty million Euro in 2015, which is small relative to other electricity system costs. The second policy keeps consumer on the standard electricity tariff but the Portuguese government pays a fraction of their bill. Thus the second policy will not increase the direct price of electricity for unsubsidized consumers because the electricity system receives revenue equivalent to what an unsubsidized consumer would pay. Overall, existing policies that shift low voltage consumers into subsidized rate classes are not shifting large costs onto unsubsidized consumers. On the other hand, these policies do show that the Portuguese government wants to control electricity price growth for vulnerable consumers. We describe these policies in detail below.

Fixed charge subsidy

In 2010, ERSE reported 5.4 million unsubsidized low voltage consumers. The Portuguese government then established, via Decree Law 138-A/2010, a subsidized low voltage rate class in order to protect economically vulnerable residential consumers.[198] For 2015, consumers on the subsidized rate pay a smaller fixed monthly fee and save 15€ - 90€ annually, based on the quantity of power (kW) the consumer contracts; in previous years, the subsidy was smaller.[122] Electricity generators contribute to a fund that covers the cost of the subsidy.[122] Consumers on the subsidized tariff pay the same price for energy as un-subsidized consumers. In the first year ERSE offered the subsidized tariff, approximately 0.7 million low voltage residential consumers subscribed; the number of un-subsidized consumers decreased to 4.8 million.[199] In 2014, the Portuguese government, via Decree Law 172/2014, further expanded eligibility for the subsidized tariff and increased the benefit the subsidized tariff provides.[200] ERSE projects that the cost of the program will increase from around 5 million Euro per year to 30 million Euro per year.[122] The 25 million Euro increase in cost of the subsidized tariff, however, is small compared with the 3.7 billion Euro that ERSE projects all low voltage consumers will pay for electricity in 2015. On the other hand, the subsidized tariff does show that the Portuguese government wants to control electricity price growth for sensitive consumers.

Electricity bill discount

The Portuguese government, via Decree Law 102/2011, also established an energy bill subsidy for economically vulnerable clients ("apoio social extrordinário ao consumidor de energia"; ASECE). The Portuguese government pays 13.8% of the electricity bills (pre-tax) of consumers that have the ASECE.[201] The 3.1 and 4.6 million Euro (nominal) that the Portuguese government spent on the program in 2012 and 2013, respectively, are small relative to the total spending on electricity for all low voltage customers.[196,197] Data for 2014 are not yet available. The energy subsidy provides further evidence that the Portuguese government wants to control electricity price growth for vulnerable consumers.

The average quantity of electricity consumed by low voltage customers

ERSE reports the average electricity consumption of a low voltage consumer decreased from 2,994 kWh/client in 2011 to 2,487 kWh/client in 2014.[5]. The average electricity consumption of consumers with a connection fee subsidy ('social tariff') also fell from 1,507 kWh/client in 2011 to 1,270 kWh/client in 2014.

Low voltage consumer electricity tariffs

[5] ERSE projects that 2015 consumption per client will be 1744 kWh. This is 30% lower than 2014, while ERSE projects overall low voltage consumer demand to increase by 2.7%. Thus we believe this is a typo and we do not report the 2015 estimate from ERSE.

Figure 9.7 shows the average price for a kilowatt-hour of electricity for low voltage consumers from 2010 through 2015, excluding taxes. Increasing electricity system costs, decreasing electricity consumption, and an increase in the tax on electricity were the primary factors that increased electricity rates.

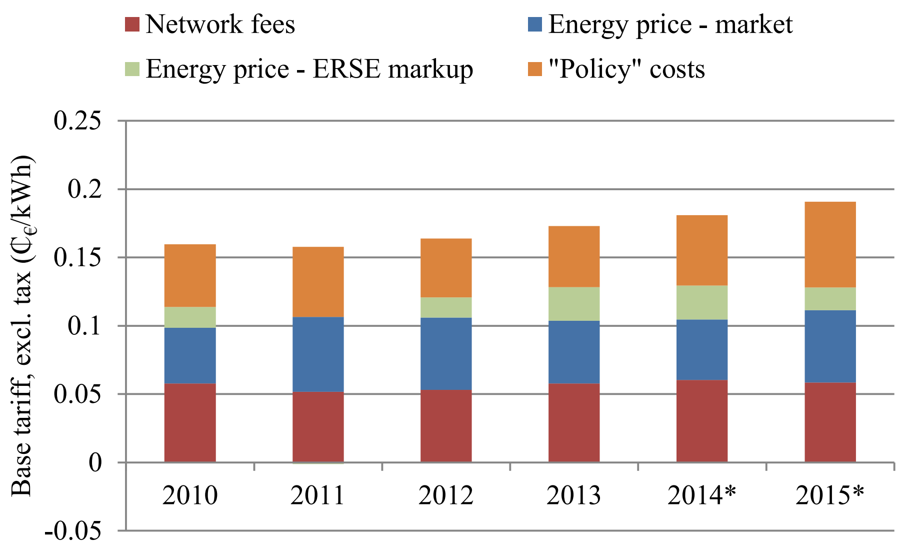


Figure 9.7. The components of the Portuguese normal low voltage tariff (i.e., residential tariff), using tariff data from [122,139–142,155]. Network fees include the fees associated with the transmission and distribution networks. The energy price is the sum of the annual average wholesale market and ancillary service prices from [123,195,202,203], except for 2014 and 2015 where no official data has been reported. For these two years, we calculate the average wholesale market price using data from [143] and add an assumed 3€ ancillary service markup, consistent with the previous data that ERSE reported to the EU.[195] The energy price markup is the difference between the annual average energy price and the energy component of the residential tariff. Policy costs are the "Global Use of System" costs and include subsidies that Portugal guaranteed to renewable generators, revenue supplements that Portugal guaranteed to certain other generators, and various other smaller costs.

Figure 9.8 shows how retail price of electricity varies based on the retailer the customer uses and the time-of-use tariff the customer selects. The Portuguese electricity regulator (ERSE) specifies the times of peak-, mid-, and off-peak periods. Therefore retailers can only chose the price they offer electricity in each period. We do not observe large variation across same-class tariffs (e.g. flat rate) except for one vendor that offers a three period time-of-use tariff with a relatively smaller peak price. Overall, nine vendors offer retail electricity service to Portuguese consumers and most vendors have at least two time-of-use tariff options (e.g. flat rate and two period).[204]

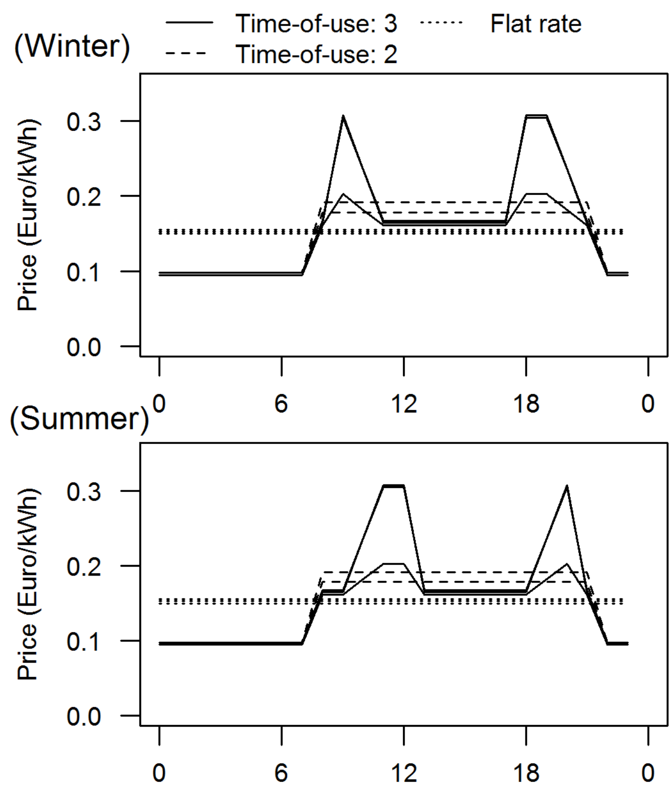


Figure 9.8. Electricity prices, excluding the 23% value-added-tax, for nine of the retail electricity tariffs that are available to Portuguese consumers.[204] We show three time-of-use tariffs for each: time-of-use tariffs with three billing time periods, time-of-use tariffs with two billing time periods, and flat rate tariffs. The Portuguese electricity regulator specifies the time of peak-, mid-, and off-peak periods. Billing periods change between winter and summer months and between week days and weekends. The tariffs in this figure show weekday tariffs for winter and summer months.

ERSE reports the contribution of each system cost to the overall low voltage consumer electricity rate. We observe that rate increases are generally in line with ERSE reported increases in the costs of energy, policy, transmission, distribution, and grid management costs. Between 2010 and 2015, network costs only increase by 0.1 ₠/kWh. Wholesale energy and ancillary service prices increased by 1.2 ₠/kWh. The change in energy costs over the period is sensitive to the initial year used in the analysis If we used 2008 as the based year for wholesale energy prices, then increase in energy prices would be negligible. ERSE overestimated wholesale market prices throughout the 2010 and 2015 period, resulting in consumers paying more for energy than the price of energy in the wholesale market. The effect of this overestimation on the change in rates between 2010 and 2015 is small because ERSE consistently overestimated energy prices in both 2010 and 2014 (the most recent year of full data). Finally, the price of Portuguese energy policies grew by 1.8 ¢€/kWh.

Two other factors also increased the low voltage consumer electricity price. First, the Portuguese government increased the value added tax on electricity from 5% to 23% at the end of 2011. Thus low voltage consumers pay the ERSE tariff plus an additional 23% value added tax for a total electricity price of 0.25 €/kWh. If the value added tax remained at 5%, the low voltage consumer price would be 0.214 €/kWh, or 0.036 €/kWh lower.

Second, low voltage consumer electricity consumption decreased 18% between 2010 and 2014. Electricity system costs did not fall in proportion to the reduction in total electricity system demand. As we discussed above, the transmission, distribution, and grid management costs decreased marginally and the total value of special regime, CMEC, and CAE generator guarantees increased substantially. Based on these data, it appears reasonable to model transmission, distribution, grid management, and special regime generator costs as demand invariant, or relatively fixed. Thus, if low voltage consumer demand had not decreased, then these fixed electricity system costs would have been spread over a larger quantity of demand. To provide an illustrative example: if low voltage consumers use the same quantity of energy in 2015 as in 2010 (21,579 GWh) and the increase in demand incurred no costs (i.e. the marginal cost of electricity is zero), then the low voltage consumer electricity price would fall from 0.2039 €/kWh to 0.1713 €/kWh. If we assume the marginal cost of electricity is 0.06 €/kWh, or approximately equal to the wholesale market price for electricity in Portugal, then the same increase in demand would cause the low voltage consumer electricity price to fall from 0.2039 €/kWh to 0.181 €/kWh. Thus, based on the assumption that transmission, distribution, grid management, and special regime generator costs are demand invariant, the reduction in low voltage consumer electricity demand was also a substantial contributor to increased electricity rates for those same consumers.

Moving forward, we expect that residential electricity tariffs will continue to increase. If the income of Portuguese consumers continues to stagnate, this may lead to further downward adjustments in the amount of electricity consumed by the average low voltage consumer. Our expectation of further rate increases is based on three lines of evidence. First, the government has not passed any legislation that alters the fundamentals of the Portuguese electricity system and the Portuguese government appears committed to meeting revenue guarantees for previously installed generators. Second, demand growth would help spread the fixed costs of the Portuguese electricity system over a larger number of kilowatt-hours. ERSE projects relatively modest electricity demand growth of 2.7% in 2015. However, ERSE over-predicted demand growth in each of the last four years and the based demand growth projection will not have a substantial effect on rates. Finally, the Portuguese tariff deficit continues to grow. If the Portuguese government does not nationalize or pay this debt in some other way, then electricity rates will need to increase in order to pay off previous and on-going tariff deficits.

9.4 Background information on Portuguese distributed generation policies

In late 2014, the Portuguese government passed Decree Law 153/2014. Decree Law 153/2014 is the most recent update to the regulatory and policy framework that governs the installation and compensation of small distributed generators. Decree Law 153/2014 is the third major policy shift for consumers that intend to install distributed generation capacity. The first began in 2001 when Decree Law 312/2001 allowed consumers to connect generating devices to the low voltage electricity grid.[205] However, the law did not change the administrative requirements for connecting a generator to the public electricity grid. Thus, distributed generators still needed to comply with administrative requirements for centralized generators.[116] Decree Law 68/2002 established a subsidy for consumer that installed distributed generation, which was equivalent to 2.50 €/W of installed solar PV capacity[6] plus the value of avoided grid electricity purchases.[206,207] This first policy phase took place from 2002 through 2007 and was characterized by very low distributed generation adoption rates.[116]

The second distribution generation policy framework began when the Portuguese government passed Decree Law 363/2007. Decree Law 363/2007 recognized the high administrative barriers that small distributed generators faced and aimed to increase the adoption of distributed generators. Therefore, the law created a special administrative process for consumers that wanted to install distributed generators with only an online registration requirement and a physical inspection requirement. Consumers that installed distributed generators could also opt to receive guaranteed payments for all electricity generated. The subsidy initially had a value of 5.62 €/W of installed solar PV capacity (over the 15 year subsidy lifetime). Rapid reductions in the cost of solar PV between 2007 and 2014 led to similarly rapid reductions in the subsidy that the government offered. The subsidy reached a low of 0.98 €/W of installed solar PV capacity in 2014.[208] Further, the law specified the maximum distribution generation capacity that consumers could connect to the grid each year. The second policy phase, from 2008 through 2013, was characterized by a streamlined connection process, relatively

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[6] In all places where we cite the present value of the subsidy we used the following assumptions: 1) each 1 kW_{DC} of installed solar PV capacity produces 1600 kWh_{AC}/y, 2) future revenues are discounted at 6% annually. Our qualitative conclusions do not change when we use different discount rates between 2% and 10% annually.

generous subsidies, high consumer demand for the subsidies, and an installation rate that was constrained by the annual installation quotas.

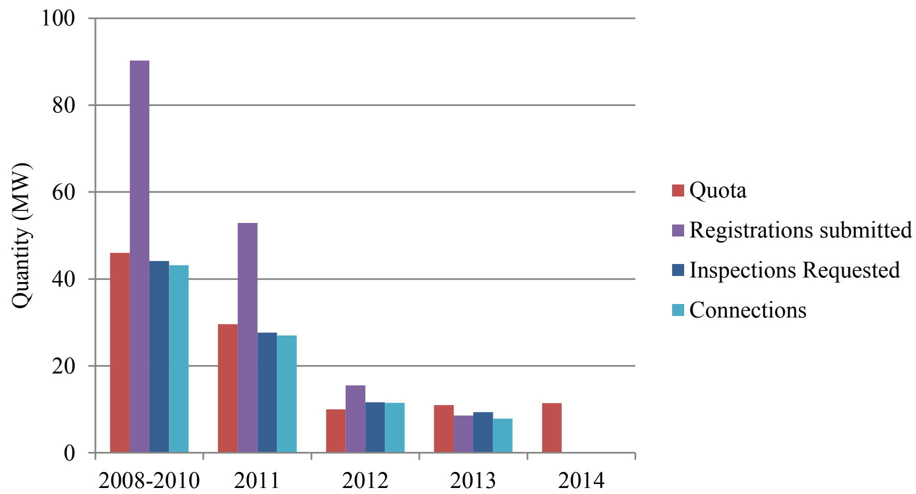

Figure 9.9. Consumer demand for the distributed generator subsidy relative to the annual installation quota. Data are from [128]. From 2008 through 2012, the total capacity of registrations submitted exceeds the annual installation quota. Consumer demand for the distributed generator subsidy was lower than the annual installation quota in 2013 and 2014. These years had first period subsidies of 2.4 €/W and 1.0 €/W of installed solar PV capacity, substantially lower than the 2012 subsidy of 3.8 €/W of installed solar PV capacity.[119,208,209]

As a result of decreasing solar PV costs, decreasing solar PV subsidies, and increasing electricity rates, distributed generation began naturally shifting from a 'sell all production back to the grid' model to an 'offset grid purchases and resell the excess to the grid' model. That is, from 2008 through 2012, consumers installed a total of 0.33 MW of general regime (unsubsidized) solar PV. Total consumer installations of unsubsidized solar PV in 2013 and 2014 grew to 4.35 MW. The third distributed generation policy framework began when the Portuguese government passed Decree Law 153/2014 in response to this trend.

First, Decree Law 153/2014 maintained the subsidized regime with administrative and quota policies that were similar to Decree Law 363/2007. However, research suggests that the present value of the 2015 subsidy (1.19 €/W of installed capacity; i.e. present value of guaranteed revenue) remains below the installed cost of solar PV, even in sunny locations such as Portugal.[120,174,210] Actual consumer demand for this subsidy will not be known until the Portuguese government releases 2015 application and connection data in 2016.

Decree Law 153/2014 also formally recognized that consumers can use distributed generators for self-consumption and, recognizing this, proceeded to update the applicable administrative, compensation, and quota regulations. Specifically, the law maintained the "register and inspect" requirement for generators above 1.5 kW but eliminated the requirement smaller generators that will not resell electricity to the grid. Further, the registration fee decreased for almost all system, from 500 € plus tax to 30 € plus tax for systems below 1.5 kW that do not wish to resell electricity to the grid. Decree Law 153/2014 dis-incentivized consumers from installing oversized distributed generators (relative to the demand of the consumer) by specifying that excess generation resold to the grid would be compensated at 90% of the wholesale market price and by limiting the power that self-consumption units could inject into the grid. For reference, wholesale market prices averaged 49 €/MWh between July 2007 and February 2015.[143] In effect, when the law established that consumers receive 90% of the wholesale market price, it also decreased the price consumers receive for excess generation. Previously, Decree Law 363/2007 specified that unsubsidized consumers receive the energy component of the retail tariff (often 60-70 €/MWh) for all excess generation.[116]

Table 9.3 summarizes the administrative, quota, and compensation policies for distributed generators in each year from 2002 to the present. Additionally, we briefly summarize below the relevant legislation and policies that govern the administrative, quota, and compensation policies for distributed generators. Overall, since 2002 Portugal has created a streamlined system for registering and connecting distributed generators to the electricity grid.

Policies that provided large subsidies for the adoption of distributed generation were very effective at incentivizing consumer adoption of distributed solar PV. However, the Portuguese government implicitly recognized that the subsidies would increase total electricity system costs when it implemented annual installation quota. Further, whether the government perceived the costs of the subsidy to be too high in absolute terms or simply relative to the cost of installing solar PV capacity, the Portuguese government dramatically reduced the value of the subsidies. The recent policy shift towards lower subsidies and a focus on self-consumption indicates that the Portuguese government remains interested in exploiting indigenous energy resources and the sustainability of solar PV, but is beginning to seriously consider the costs associated with these policy goals. Indeed, the Portuguese government cites both the environmental benefits and the goal of maintaining reasonably priced energy in the introduction of the most recent distributed generation policy update (Decree Law 153/2014).

Table 9.3. A summary of important variables that affect the revenue that low-voltage consumers will receive when they invest in distributed solar PV capacity. The units for the Potential Compensation column are not all the same. We show the wholesale LMP because this is the price that independent power producers could obtain for solar PV output. Similarly, the retail tariff is the price that low voltage consumers avoid paying when solar PV generation avoids the need for additional purchases from the grid. Finally, we report the present value of the subsidy that the government offers in each year based on the assumptions outlined in footnote 1. Data are from [116–119,122,134,139–143,153–155,205,207–209].

Year	Controlling legislation	Potential Compensation			Administrative burden	Capacity quota
		Wholesale LMP *€/MWh*	Retail tariff *€/MWh*	Subsidy *€/W_{DC}*		*MW*
2002	Decreto-Lei 312/2001	n/a		2.5 + tariff	Same as centralized generator	None
2003	Decreto-Lei 312/2001	n/a		2.5 + tariff	Same as centralized generator	None
2004	Decreto-Lei 312/2001	n/a		2.5 + tariff	Same as centralized generator	None
2005	Decreto-Lei 312/2001	n/a		2.5 + tariff	Same as centralized generator	None
2006	Decreto-Lei 312/2001	n/a		2.5 + tariff	Same as centralized generator	None
2007	Decreto-Lei 312/2001	€ 56	€ 150	2.5 + tariff	Same as centralized generator	None
2008	Decreto-Lei 363/2007	€ 72	€ 154	€ 4.8 *	Special low voltage connection process	10
2009	Decreto-Lei 363/2007	€ 40	€ 161	€ 4.8 *	Special low voltage connection process	12
2010	Decreto-Lei 363/2007	€ 40	€ 168	€ 4.8 *	Special low voltage connection process	24
2011	Decreto-Lei 118-A/2010	€ 52	€ 164	€ 4.4	Special low voltage connection process	29.6
2012	Decreto-Lei 118-A/2010	€ 50	€ 201	€ 3.8	Special low voltage connection process	10
2013	Decreto-Lei 118-A/2010	€ 44	€ 216	€ 2.4	Special low voltage connection process	11
2014	Decreto-Lei 118-A/2010	€ 41	€ 227	€ 1.0	Special low voltage connection process	11.45
2015	Decreto-Lei 153/2014	€ -	€ 251	€ 1.2	Special low voltage connection process**	20***

* Consumers that installed distributed generators in 2008-2010 did not know their subsidy rate after five years. To calculate the average present value of a kWh of generation, we use the current subsidy rate for the last 10 years of the subsidy (95 €/MWh) in place of the unknown quantity . We note that this may not reflect consumers' expectations of the year 6-15 subsidy when they installed the generator.

** Solar PV arrays for self-consumption with a capacity ≤ 200W only need to submit "prior notification" to the regulator.

*** Solar PV arrays for self-consumption are not subject to a annual capacity quota.

Summary of Individual Laws and Policy Changes

Decree Law 312/2001

In 2001, Decree Law 312/2001 legalized distributed generation, including solar PV, by allowing residential and other small consumers to connect generation equipment to the low voltage network. Decree Law 68/2002 complemented Decree Law 312/2001 and established a subsidy for consumer that installed distributed generation, which was equivalent to 2.50 €/W of installed solar PV capacity plus the value of avoided grid electricity purchases.[206,207] However, neither law created a special administrative process for small distributed generators and therefore distributed generators needed to comply with the same requirements as large centralized generators.[116] Finally, Decree Law 312/2001 did not establish a limit on the annual quantity of distributed generation capacity that low voltage consumers installed. However, a provision in the law allowed the grid operator to reject permit applications when the electricity grid was not able to accept additional distributed capacity at the connection point of the consumer.[205]

Despite the legality of connecting generation equipment to the grid, low voltage consumers did not install significant distributed generation capacity between 2002 and 2007.[116]

Decree Law 363/2007

The Portuguese government passed Decree Law 363/2007 in 2007 which overhauled the existing distributed generation policy and regulatory framework. The Decree Law established the connection process, the installation quota and the compensation mechanisms for distributed "micro" generators. The capacity limit for an individual "micro" generator was 5.75 kW (expect for condominiums) and thus the target market of the policy was residential and potentially some very small commercial customers. A separate policy establishes the regulations and compensation scheme for distributed "mini" generators with capacities larger than 5.75 kW.

Decree Law 363/2007 created an online connection process that was specially designed for small distributed generators. In this process, the consumer completed an initial registration that demonstrated an interest in installing a distributed generator. If the consumer correctly completed the registration forms and total installations did not exceed the annual quota, then the consumer received a provisional registration and could install the distributed generator. The consumer was then responsible for paying the registration fee, which was originally 250 € plus tax but then increased to 500 € plus tax.[211] [212] After the consumer paid the registration fee and installed the distributed generator, the consumer requested an inspection from the specified governmental entity. If the distributed generator passed the inspection, it was allowed to connect to the grid and begin operation. If the distributed generator failed the inspection, the consumer requested an additional inspection and paid a re-inspection fee. Decree Law 363/2007 limited total distributed generation installations by setting an annual installation quota (10 MW in the first year, growing by 2 MW each year thereafter) and limited the penetration of distributed generators in a given area to 25% of the capacity of the electrical (transformer) substation.

Decree Law 363/2007 established two compensation regimes for distributed generators, a subsidized regime and a general regime. The subsidized regime was a guarantee that default distribution utility ("comercializador de último recurso" or supplier of last resort) would purchase all generation at the rate that the government published. The present value of the subsidy (i.e. present value of guaranteed revenue over the life of the subsidy) started at 5.1 €/W of installed PV capacity but decreased for each 10 MW of total capacity that consumers installed. In order to qualify for the subsidized regime, the law required that consumers met two extra requirements. First, the consumer needed to install a solar hot water heater at the location the distributed generation system was installed. Second, the installed capacity of the distributed generation unit could not exceed 3.68 kW and the power injected into the grid could not exceed 50% of the contracted power of the consumer.

Consumers that opted for the general regime also resold all electricity generation to the default distributed utility. However, the price that consumers received for each unit of electricity sold was equal to the energy component of the regulated low voltage consumer tariff, which has not exceeded 70 €/MWh since 2010.[122] The law did not place any extra requirements on consumers that opted for the general regime. Thus the capacity of general regime distributed generators could not exceed 5.75 kW and the power injected into the grid could not exceed 50% of the contracted power of the consumer.

Decree Law 118-A/2010

In October 2010, the Portuguese government passed Decree Law 118-A/2010 which was a minor revision and republication of Decree Law 363/2007. The most significant change was that Decree Law 118-A/2010 stated that both the subsidy and annual distributed generation capacity quota were to be updated annually via an administrative (i.e. not legislative) process. The law then replaced, for the last several months of 2010, the original 2010 quota and subsidy with an increased quota and nearly unchanged subsidy. Decree Law 118-A/2010 also altered the compensation scheme. Previously, Decree Law 363/2007 specified that distributed generators received a subsidy for fifteen years, split into two periods. For the first five years, the generator received a pre-specified and fixed subsidy rate. For the final ten years, the generator received a subsidy rate that changed annually. Thus, consumers that installed distributed generators under Decree Law 363/2007 faced revenue uncertainty in years six through fifteen because the future subsidy rates were unknown. Decree Law 118-A/2010 defined the pre-specified subsidy rate for all fifteen years of the subsidy.

Administrative updates

The Directorate General for Energy and Geology (Direcção-Geral de Energia e Geologia; DGEG) was responsible for updating both the annual subsidy rate and the distributed generation quota.[117] DGEG published an updated subsidy rate and capacity quota for 2011 through 2014. The subsidy decreased in each consecutive year and the capacity quota never exceeded 30 MW per year.[118,119,208,209] In fact, for 2014, the present value of the subsidy was 1.0 €/W of installed solar PV capacity, substantially lower than the initial 2008 subsidy of 5.1 €/W of installed solar PV capacity.[116,208]

Decree Law 153/2014

In October 2014, the Portuguese government again updated the policy and regulatory framework for distributed generators, including solar PV generators. Decree Law 153/2014 dropped the previous distinction between “mini” and “micro” generators, where “micro” generator rules and regulations had applied to residential and potentially very small commercial consumers. In place of the previous distinction, the law created the distinction between distributed generators that consumers use to offset the home or businesses electricity demand (self-consumption units) and distributed generators that consumers use to sell electricity to the grid (small production units).[134] Residential consumers can theoretically participate in either program. For both self-consumption units and small production units, the law added a new requirement that consumers obtain liability insurance to cover damages that distributed generators could inflict on the grid.[134]

Decree Law 153/2014 established the administrative, compensation, and sizing limits for self-consumption distributed generation units. Three changes simplified the administrative process, relative to Decree Law 118-A/2010. First, the consumer only needs to notify the regulator of the installation if the consumer does not want to resell excess electricity production to the grid and the unit is smaller than 1.5 kW. Units larger than 1.5 kW or those connected to the grid must follow the same registration and inspection process that existed under Decree Law 118-A/2010. Second, the distributed generator registration fee changed from 500 € plus tax for all units to a tiered system based on capacity and also decreased the fee for small units.[212,213] Consumers that do not resell electricity to the grid and have a distributed generation unit smaller than 1.5 kW do not pay any registration fee.[213] Consumers that do resell electricity to the grid and have a distributed generation unit smaller than 1.5 kW only pay 30 € plus tax.[213] Third, the law does not set any capacity quota for self-consumption units. However, Decree Law 153/2014 does not allow self-consumption units to inject a quantity of power into the grid that is larger than the consumers contracted power. This requirement essentially limits the capacity of solar PV arrays to the contracted power of the consumer, assuming the consumer will have low demand during at least one hour of high solar PV output.

Consumers derive economic value from self-consumption units by avoiding purchasing electricity from the grid. The Portuguese energy regulator ERSE projects the average tariff for low voltage consumers in 2015 will be about 250 €/MWh after all taxes and fees.[122] Thus, consumers whose electricity demand is coincident with solar PV output can realize large bill savings. On the other hand, the supplier of last resort purchases all excess generation for 90% of the monthly average wholesale energy price, which averaged 49 €/MWh between July 2007 and February 2015.[143] Decree Law 153/2014 also establishes a consumer to grid compensation mechanism if the total capacity of self-consumption generators exceeds 1% of total system capacity, or about 1,800 MW in 2013.[121] In this mechanism, the owners of distributed generation must repay a certain fraction of the "economic and energy policy" costs that the consumer avoids via self-consumption. We note that the threshold at which consumers begin to repay a fraction of the "economic and energy policy" costs is over 18 times the currently installed quantity of distributed solar PV in Portugal.[128,134] Thus, this is not likely to be a relevant factor when assessing the economics of solar PV in Portugal for some time.

Decree Law 153/2014 also established the administrative, compensation, quota, and sizing regulations for small production units. Small production units follow the registration and inspection process that existed under Decree Law 118-A/2010 and the annual installation capacity quota is 20 MW. Consumers must also size their distributed generation unit such that the total quantity of electricity exported to the grid (i.e. electric energy, kW) does not exceed 50% of the total demand of the consumer. Once the small production unit is installed, the supplier of last resort purchases all the electricity the system produces at a fixed price for fifteen years. The Portuguese government publishes the applicable purchase price ahead of time. However, instead of the government administratively determining the purchase price, an auction occurs where all "accepted" capacity receives the price bid by the last accepted (i.e. highest price) distributed generation unit.[134] The present value of the subsidy for all consumers that install solar PV "small production" generators in 2015 is 1.2 €/W of installed solar PV capacity.[214] Consumers that also install electric vehicle charging stations, solar hot water heaters, or both are eligible to receive a subsidy up to 15% larger.[214]

9.5 Calculating real electricity price growth

Table 9.4. Various data on electricity tariffs for low-voltage consumers in Portugal between 2007 and 2015. Data are from [122,139–142,153–155]**.**

Tariff Component		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
"Preço médio da tarifa de energia"	€/kWh				0.0561	0.0534	0.0678	0.0704	0.0692	0.0695
Evolução do preço médio das tarifas de acesso ás redes BTN (com IP)	€/kWh				0.0984	0.0989	0.0919	0.0985	0.1073	0.1157
Preço médio da tarifa de Comercialização em BTN	€/kWh				0.0051	0.0043	0.004	0.0043	0.0045	0.0056
Estrutura do preço médio das tarifas de acesso ás redes em 2011 (BTN customers)	(%)									
Low voltage fee					*35%*	*31%*	*34%*	*35%*	*32%*	*30%*
Medium voltage fee					*9%*	*8%*	*10%*	*10%*	*9%*	*8%*
High voltage fee					*2%*	*2%*	*2%*	*2%*	*2%*	*2%*
Transmission fee					*7%*	*7%*	*7%*	*8%*	*8%*	*6%*
Global system fee					*47%*	*52%*	*47%*	*46%*	*48%*	*54%*
Average price*	€/kWh	0.143	0.1464	0.1533	0.1596	0.1561	0.1635	0.1755	0.1849	0.2039
Simple sum of tariff components	€/kWh				0.1596	0.1566	0.1637	0.1732	0.1810	0.1908
Final price, including VAT****	€/kWh	0.150	0.154	0.161	0.168	0.164	0.20	0.22	0.23	0.25
Annual tariff growth, BTN**,***	(%)		2.4%	4.7%	4.1%	-2.2%	4.7%	7.3%	5.4%	10.3%

*As reported by ERSE, for BTN clients. For 2011-2013 tariffs, this is the "preço médio de referência de venda a clientes finais". For the 2014-2015, this is the "preço médio das tarifas transitórias".

**Growth excludes additional taxes

*** As calculated by the authors using changes in the data from the "Average price" row

**** The VAT changed from 5% to 23% in October 2011

Table 9.4 shows electricity tariff data from the Portuguese energy regulator (ERSE) for 2007 through 2015. The final price for low-voltage consumers in 2007 was 0.15€/kWh and grew to 0.25€/kWh in 2015. The 2007 price includes the previous 5% value added tax and the 2015 price includes the current 23% value added tax. If the value added tax did not increase from 5% to 23%, the final price of electricity for low-voltage consumers would be 0.214€/kWh. We calculate the nominal compound annual growth rate for electricity prices based on Equation 8.3. Equation 8.4 shows Equation 8.3 when we solve for the nominal compound annual growth rate of electricity prices. The nominal compound annual growth rate for electricity prices was 6.6% including the tax increase or 4.5% excluding the tax increase.

$$p_o = p_i * (1 + r_{nom})^t \tag{8.3}$$

$$r_{nom} = e^{\left(\frac{ln\left(\frac{p_o}{p_i}\right)}{t}\right)} - 1 \tag{8.4}$$

Real electricity price growth depends on both nominal electricity price growth and the underlying inflation rate. Equation 8.5 shows that the relationship between real and nominal electricity price growth is nominal electricity price growth divided by inflation, or in other words, the rate that electricity prices increase above and beyond the general inflation rate. We estimate that the compound annual inflation rate in Portugal since 2007 is around 1.5% (over this period, the annual inflation rate ranged from -1% to nearly 4%).[215,216] Thus, between 2007 and

2015, the real compound annual growth rate of electricity prices in Portugal was 5% (including the tax increase) or 3% (excluding the tax increase).

$$(1 + r_{real}) = \frac{(1 + r_{nom})}{(1 + i)} \tag{8.5}$$

9.6 Modeling solar PV output in Portugal

In order to model the attractiveness of an investment in solar panels, we first model the amount of electricity produced by a solar photovoltaic (PV) array in each hour over the course of a year. Hourly electricity production is necessary because other parts of the benefit-cost analysis model are based on an hourly timescale. For example, the private costs avoided by producing solar electricity depend on whether the consumer uses the electricity directly or exports the electricity to the grid. Also, we model changes in hourly wholesale market prices due to changes in demand, which requires understanding how consumer demand changes on an hourly basis.

The power output of a solar PV array can be defined as by Equation 8.6; energy production is the integral of power output over time. *P* is the panel power output in kilowatts (W), □$_c$ is the efficiency of conversion from solar radiation to electricity efficiency for the solar cell measured at some reference conditions, *A* is the area of the panel array (m^2), and G_T is the solar radiation flux (irradiance) on the array (W/m^2).

$$P = n_c * A * G_T \tag{8.6}$$

We must also consider that the efficiency of solar cells (□$_c$) depends on the temperature of the solar cells (T_c). A review conducted by Skoplaki (2009) finds that this relationship is well approximated by the linear relationship shown in Equation 8.7.[144] The reference cell temperature (T_{ref}) is normally defined as 25 ^{0}C.[144] The overall cell temperature coefficient (β_{ref}□ is an empirical measure of how fast efficiency degrades as temperature increases. A wide range of studies report this value to be between 0.003 and 0.006 $^{0}C^{-1}$ for crystalline silicon solar panels; of these studies, most report this value to be between 0.004 and 0.005 $^{0}C^{-1}$.[144]

$$n_{c,T} = n_{c,ref} * \left[1 - \beta_{ref}(T_c - T_{ref})\right] \tag{8.7}$$

In turn, Skoplaki (2008) empirically relates the temperature of the solar cells (T_c) with the ambient (environmental) temperature (T_a), the wind speed (V_f), and solar irradiance (G_T), and a mounting coefficient (ω) that varies depending on how the solar array is installed (Equation 8.8).[145] Equation 8.8 uses solar cell reference information, including: the normal operating cell temperature ($T_{c,NOCT}$) at a defined ambient temperature ($T_{a,NOCT}$), the cell temperature at which the reference efficiency is reported ($T_{c,ref}$), and other variables described above. This equation assumes heat transfer between the panel and the environment is dominated by forced convection (i.e., wind) and uses the "free-flow wind velocity" and not ground level wind speed. Table 9.5 reproduces the recommended mounting coefficients from Skoplaki (2008).

$$T_c = T_a + \omega\left[\left(\frac{G_T}{G_{T,NOCT}}\right)\left(\frac{8.91 + 2V_{f,NOCT}}{8.91 + 2V_f}\right)\left(T_{c,NOCT} - T_{a,NOCT}\right)\left(1 - \frac{\eta_{ref}}{\tau\alpha}\left(1 + \beta_{ref}T_{c,ref}\right)\right)\right] \tag{8.8}$$

Table 9.5. Reproduction of mounting coefficients for use in Equation 8.8. Originally reported by Skoplai (2008) [145]

PV array mounting type	ω
Free standing	1

Flat roof	1.2
Sloped roof	1.8 (1.0 - 2.7)
Facade integrated	2.4 (2.2 - 2.6)

We use Equations 8.6, 8.7, and 8.8, in combination with meteorological station data on solar irradiance, ambient temperature, and free-flow wind speed from the city of Lisbon, Portugal to estimate hourly solar production from a one kilowatt (1kW) solar PV array.[149] The one kilowatt sizing refers to output at reference conditions, specified in Table 9.6. Table 9.6 also shows our baseline values for the cell temperature coefficient (β_{ref}) and mounting type (ω). Estimated array production does not include other losses associated with using the electricity, including the conversion from direct to alternating current.

Table 9.6. Baseline model parameters used to estimate solar PV power output and energy production. All model parameters are for solar panels based on crystalline silicon.

Variable	Symbol	Value	Notes
Solar cell reference efficiency	$\eta_{c,ref}$	0.12	From the review conducted by Skoplaki (2009) [144]
Cell temperature for which reference efficiency is reported	$T_{c,ref}$	25 ^{0}C	From the review conducted by Skoplaki (2009) [144]
Solar cell temperature coefficient	β_{ref}	0.004 $^0C^{-1}$	From the review conducted by Skoplaki (2009) [144]
Irradiation for which reference efficiency is reported	G_{ref}	1000 W/m^2	From the review conducted by Skoplaki (2009) [144] and [175]
Normal operating cell temperature	$T_{c,NOCT}$	47 ^{0}C	From the review conducted by Skoplaki (2008) [145]
Ambient temperature for which normal operating cell temperature is reported	$T_{a,NOCT}$	20 ^{0}C	Schults, JW, 1977 USDOE; Cooling of solar cells (1989)
Solar irradiation	$G_{T,NOCT}$	800 W/m^2	Schults, JW, 1977 USDOE; Cooling of solar

Normal operating wind velocity	$V_{f,NOCT}$	1 m/s	cells (1989) Schults, JW, 1977 USDOE; Cooling of solar cells (1989)
Area of the solar array	A	10.4 m^2	Calculated in order that the system produces 1kW at reference conditions
Mounting type coefficient	ω	1	Value for freestanding arrays, from Skoplaki (2008) [145]
Product of glazing transmittance and solar absorptance	$\tau\alpha$	0.9	From the review conducted by Skoplaki (2008) [145]

In order to validate our model, we compare our modeled solar PV output with the European Union's Joint Research Center Photovoltaic Geographic Information System (pvGIS) modeled output. To start, we compare solar irradiance input data, a key determinant of solar panel output. Our meteorological data has annual average solar irradiance that is 9% less than the pvGIS model (Figure 9.10a). Next we compare the electricity production of a one kilowatt PV array (Figure 9.10b). Our annual average modeled electricity production is 3.1% higher than the pvGIS model, despite smaller estimated solar irradiance. While the pvGIS model uses a different empirical relationship to calculate solar cell efficiency which does not account for the cool effects of wind, we are able to rule this out as the cause of the difference. This is because when we calculate solar array electricity production using the pvGIS equations to determine solar cell efficiency, our modeled electricity production is 0.5% lower than the pvGIS model. This is despite the 9% less solar irradiation received by the panels. Given the broad literature that uses, and has validated, the empirical relationships we use to estimate PV array electricity production, we judge the model sufficient to perform the cost-benefit analysis at hand. [144,145]

a)

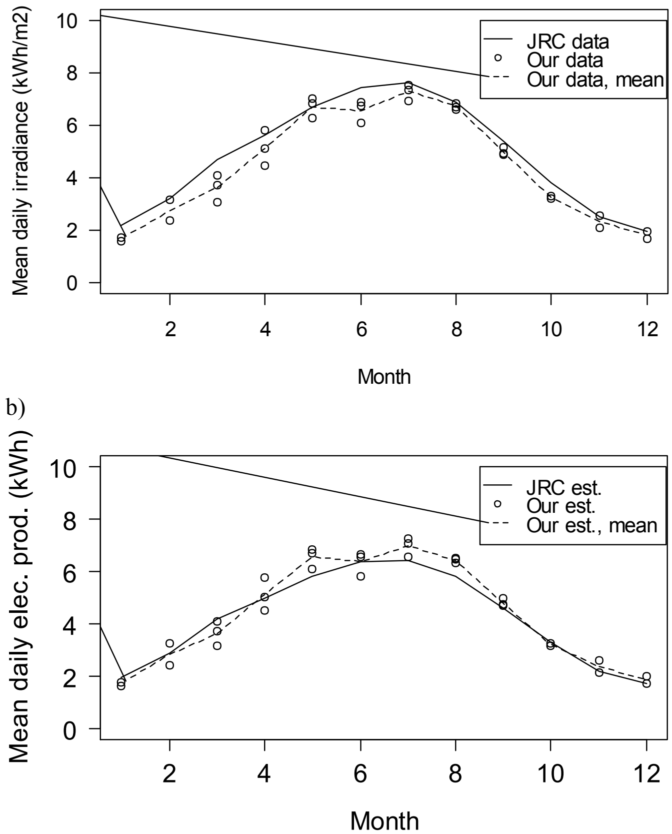

Figure 9.10. Comparison of the solar PV electricity production model we create and the pvGIS solar PV electricity production model. A) shows a comparison of average daily solar irradiance for our data set [149] and average daily solar irradiance from the pvGIS model run for Lisbon, Portugal using the Climate-SAF PVGIS solar irradiation database. B) shows average daily energy production from an one kilowatt PV array. Our data set contains more than 12 months of data so points indicate individual monthly values and the dashed line shows the mean of all data for each month.

9.7 Levelized cost of solar PV

The levelized cost of energy (LCOE) is a common metric that researchers and decision makers use to discuss different generation options. In its simplest form, the LCOE divides the sum of capital cost loan payments and variable operating expenses by the quantity of electricity generated (Equation 8.9). Where *LCOE* is the levelized cost of electricity, '*c*' is the project capital cost, '*i*' is the weighted average cost of capital, '*n*' is the project (loan) lifetime, '*o*' is operations and maintenance costs (the subscript '*f*' represents fixed O&M costs, '*v*' represents variable O&M costs, 'g' is the amount of electricity generated, 'η' is the efficiency (or heat rate) of the generator, and 'f' is the fuel cost.

$$LCOE = \frac{c * \left[\frac{i * (1+i)^n}{(1+i)^n - 1}\right] + o_f}{g} + \eta * f + o_v \tag{8.9}$$

The levelized cost of electricity for solar PV arrays will not remain constant over time in either nominal or real (i.e. current) Euro. This occurs because the amount of electricity that the solar array generates will decrease slowly over time and because, when we consider inflation, constant nominal loan payments over time result in decreasing real (i.e. current Euro) loan payments over time. Therefore, we calculate the LCOE for solar PV arrays in Portugal for each year of the panel's lifetime. Table 9.7 shows the LCOE of a 200 W solar array and a 1,000 W solar array, each with different capital costs. We assume that the consumer has a 5% real cost of capital and inflation is 2% per year, resulting in a nominal loan interest rate of 7.1%. Our LCOE estimates are higher than other research (e.g. [210]) because we use a 15 year panel lifetime, the 200 W PV array has a capital cost of nearly 4 €/W which is consistent with current advertised prices in Portugal, and Portugal does not exempt solar arrays from the 23% value added tax.

Table 9.7. The levelized cost of electricity for two different solar arrays that have different capital costs.

Year	**System LCOE (real €)**			
	200 W		1000 W	
0	€	0.26	€	0.22
1	€	0.26	€	0.22
2	€	0.26	€	0.21
3	€	0.25	€	0.21
4	€	0.25	€	0.21
5	€	0.25	€	0.20

6	€	0.24	€	0.20
7	€	0.24	€	0.20
8	€	0.24	€	0.20
9	€	0.23	€	0.19
10	€	0.23	€	0.19
11	€	0.22	€	0.19
12	€	0.22	€	0.18
13	€	0.22	€	0.18
14	€	0.22	€	0.18

9.8 Figures summarizing Iberian Peninsula electricity market data

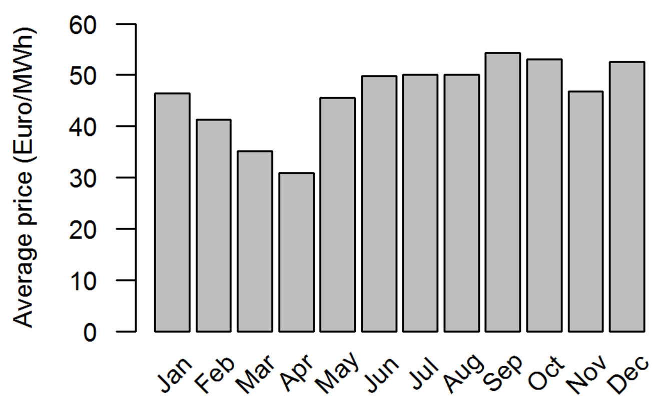

Figure 9.11. Monthly average wholesale electricity prices (€/MWh) in Portugal from July 2010 through February 2015. Data are from [143].

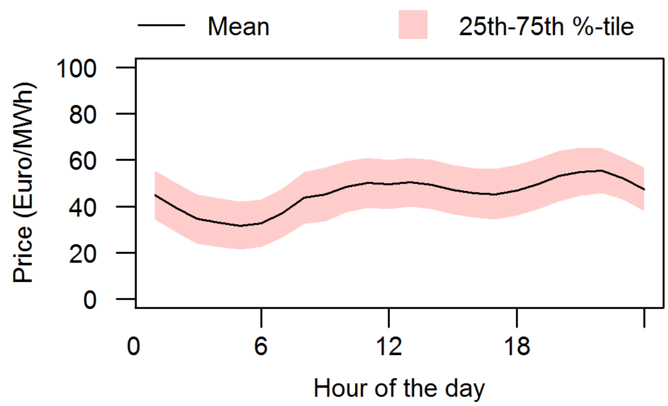

Figure 9.12. The mean and interquartile range of wholesale electricity prices (€/MWh) for each hour of the day. Data are from July 2010 through February 2015, from [143].

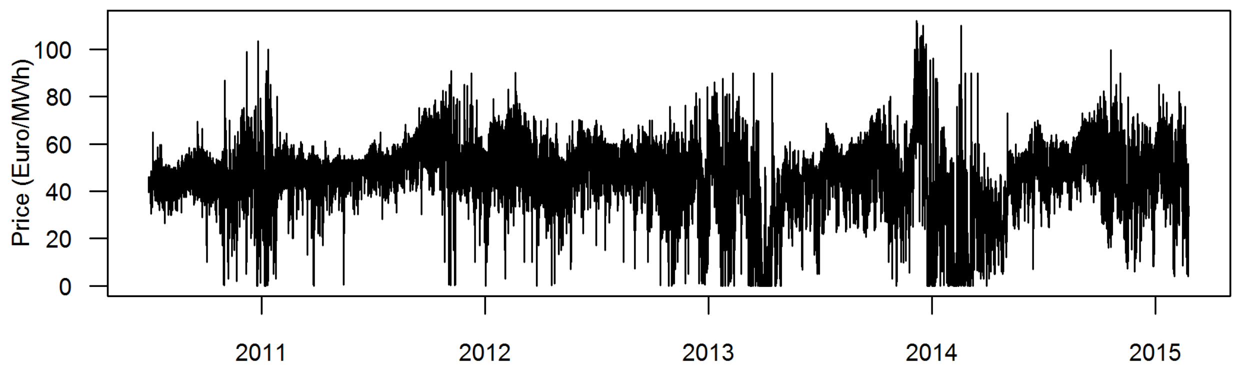

Figure 9.13. Hourly wholesale electricity prices (€/MWh) from July 2010 through February 2015. Data are from [143].

9.9 Quantifying the marginal generator in the Portuguese electricity system

Various types of electricity generators serve electricity demand in Portugal. In order to identify the effect of adding additional solar PV capacity into the electricity system, we need to understand how the output from a solar array may affect existing grid generation patterns. We evaluate this from a decade-scale perspective: how has the generation mix in Portugal changed in response to the large growth of non-dispatchable generation? Figure 9.14 shows total generation from dispatchable electricity generators each year since 2005. We define net demand as total demand minus hydro, wind, "must-take" co-generation, and solar electricity. We define dispatchable generators as coal, natural gas, and oil/other power plants and electricity imports from Spain. We assume hydro is not dispatchable, on an annual basis, based on the assumption that hydro generators will use all available water to generate electricity in each year and thus annual generation is a fixed quantity solely dependent on that year's weather conditions. Despite 16 TWh reduction in dispatchable generator generation from 2005 to 2013, which was a result of the 17 TWh growth in non-dispatchable generation and minimal demand growth, each dispatchable resource except "other" generators (including oil-fired generators) continues to meet some fraction of net demand (i.e. total demand minus non-dispatchable generation).

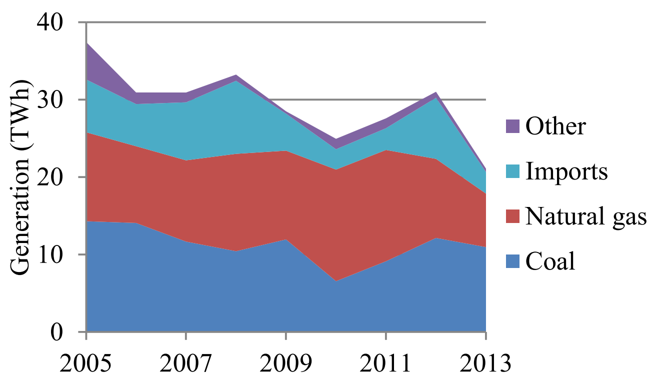

Figure 9.14. The quantity of generation (TWh) from each dispatchable resource type in the Portuguese electricity system. Data are from [108,121,173,217–219]

We then regress the change in dispatchable generation against the change in net demand using ordinary least squares (Table 9.8). Only imports show a change in total electricity generation for a change in net demand that is statistically different than zero. Further, a two-tailed t-test for the significant of the difference between the means of two independent samples suggests that the mean change in imports is statistically different from the mean change in coal, natural gas, and other generation (t-tests not shown). On the other hand, we note than the value of the estimator on the change in imports is 0.62. This indicates that the mean change imports are 0.62 megawatt-hours for each one megawatt-hour change in net demand. Other resources are likely to contribute to meeting changes in net demand, even if this conclusion is not statistically supported. The reduction in coal, natural gas, and oil + other generation between 2005 and 2012/13 supports this hypothesis. Therefore, we judge that identifying the specific class of generator that responds to a change in net demand is not feasible using our existing data. To overcome the uncertainty in the type of generation that solar PV generation displaces, we parameterize the avoided costs of each resource type and vary the generation costs that solar PV generation avoids and then vary this parameter as part of the sensitivity analysis.

Table 9.8. The regressions we used to estimate the effect of a change in net demand on the quantity of electricity that each dispatchable resource generates. Data are from the Portuguese network operators from 2005 through 2013.[108,121,173,217–219] **Thus we have eight data points, which are the differences between the variable in year 'i' and 'i-1' (2013-2012, 2012-2011, … , 2006-2005).**

Regression	Estimator	Mean	Std. Error	t-value	P[>|t|]
$\Delta gen_{coal} = \beta_o + \beta_1 * \Delta d_{net} + \varepsilon$	$\widehat{\beta_o}$	-18	1100	0.02	0.99
	$\widehat{\beta_1}$	0.20	0.22	0.89	0.41
$\Delta gen_{ng} = \beta_o + \beta_1 * \Delta d_{net} + \varepsilon$	$\widehat{\beta_o}$	-340	1000	-0.34	0.75
	$\widehat{\beta_1}$	0.11	0.20	0.57	0.59
$\Delta gen_{oth} = \beta_o + \beta_1 * \Delta d_{net} + \varepsilon$	$\widehat{\beta_o}$	-410	500	-0.82	0.45
	$\widehat{\beta_1}$	0.07	0.10	0.70	0.51
$\Delta import = \beta_o + \beta_1 * \Delta d_{net} + \varepsilon$	$\widehat{\beta_o}$	770	740	1.0	0.34
	$\widehat{\beta_1}$	0.62	0.15	4.2	0.006